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 RELIABILITY STANDARDS MOD-032-2, IRO-010-6, AND TOP-003-8

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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 three proposed Reliability Standards:

- Reliability Standard MOD-032-2 – Data for Power System Modeling and Analysis;
- Reliability Standard IRO-010-6 – Reliability Coordinator Data and Information Specification and Collection; and
- Reliability Standard TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection.

The proposed Reliability Standards[4] would advance the reliability of the Bulk-Power System by establishing requirements addressing the provision of Inverter-Based Resource (or "IBR") model data and parameters. Such information is needed to assure accurate representation of IBR performance within system models. Assuring accurate representation of IBRs is necessary as the Bulk-Power System transitions from a resource mix consisting primarily of large synchronous resources to one that is increasingly reliant on IBRs.

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1 16 U.S.C. § 824o.

2 18 C.F.R. § 39.5 (2025).

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.

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 data sharing and modeling by November 4, 2025.[5] As discussed in detail below, the proposed Reliability Standards are part of a suite of standards that collectively respond to the Commission's directives for requirements addressing data sharing and data and model validation for IBRs, including IBRs that are connected to the Bulk-Power System as well as IBRs that are connected to a distribution system but in the aggregate have a material impact on the Bulk-Power System. This proposed framework consists of the following standards and definitions:

- Proposed definition of the term Distributed Energy Resource (DER), for inclusion in the *Glossary of Terms used in NERC Reliability Standards*;
- Proposed Reliability Standard MOD-032-2 – Data for Power System Modeling and Analysis;
- Proposed Reliability Standard IRO-010-6 – Reliability Coordinator Data and Information Specification and Collection;
- Proposed Reliability Standard TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection;
- Proposed Reliability Standard MOD-026-2 – Verification and Validation of Dynamic Models and Data, and the proposed definitions of Model Validation and Model Verification (*separately filed, concurrently with this petition*); and
- Proposed Reliability Standard MOD-033-3 – Steady-State and Dynamic System Model Validation (*separately filed, concurrently with this petition*).

Proposed Reliability Standard MOD-032-2 would require Planning Coordinators/Transmission Planners to include in their data specifications and reporting

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

procedures information necessary to model IBRs in the planning area and to identify the entities responsible for providing such information. In so doing, those entities will be required to provide the information, in estimated form if necessary, so that Bulk-Power System planners can build system models for use in planning studies that accurately reflect the performance and characteristics of those IBRs. Similarly, the proposed standard would require Planning Coordinators/Transmission Planners to include in their data specifications and reporting procedures information necessary to model distribution-connected generation resources (Distributed Energy Resources or "DERs"), that in the aggregate can affect the reliable operation of the Bulk-Power System.

Proposed Reliability Standards IRO-010-6 and TOP-003-8 would reinforce that Reliability Coordinators, Transmission Operators, and Balancing Authorities are to request IBR-specific data and parameters in their data specifications as needed for operations purposes. Where model submissions are required, responding entities should provide models that are generally consistent with those provided for planning purposes under proposed Reliability Standard MOD-032-2.

The proposed standards would establish the uniform framework for modeling IBRs contemplated by the Commission in Order No. 901 that would be leveraged by Bulk-Power System operators and planners for conducting system studies. Additional work is underway to complete the development of proposed Reliability Standards responsive to the Commission's Order No. 901 directives relating to such studies by the 2026 deadline, 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 G); and the retirement of currently effective Reliability Standards MOD-032-1, IRO-010-5, and TOP-003-7.

As required by Section 39.5(a) of the Commission's regulations,[6] 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 31, 2025 (Exhibit H), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[7] (Exhibit C).

I. SUMMARY

Models provide the foundation of virtually all power system studies used to assess the reliability of the Bulk-Power System. Power system studies rely on models to predict system performance under various conditions. If models are too optimistic, it could result in grid under-investment, unsafe operating conditions, and power outages. If models are too pessimistic, it could result in overly conservative grid operation and under-utilization of network capacity. It is therefore important that models, including all their data, are complete, accurate, and up to date.

Over the last decade, the Bulk-Power System has undergone a remarkable transformation. The resource mix, once consisting generally of large, synchronous generators, is increasingly comprised of relatively smaller IBRs and DERs. Such resources have unique technical and operational characteristics which must be modeled accurately in system studies. NERC and the Commission, however, have identified deficiencies in how these resources are modeled,

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6 18 C.F.R. § 39.5(a).

7 *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).

deficiencies which have implications for the system studies that rely on these models and the actions that are taken in response to these studies. Several Bulk-Power System events in recent years have demonstrated the risks to reliability that may result from unexpected IBR performance. Further, failing to understand the nature and extent of the IBRs and DERs connected to or affecting the Bulk-Power System can affect how entities plan for reliable operation of the Bulk-Power System.

In recognition of the risks posed by the rapid growth of IBRs, the Commission issued Order No. 901 in 2023. Order No. 901 highlighted the need for a comprehensive set of Reliability Standard requirements addressing all manner of issues related to IBR performance, operations, and planning. Previous work has addressed Commission directives from this order relating to IBR performance and disturbance monitoring capabilities. Proposed Reliability Standards MOD-032-2, IRO-010-6, and TOP-003-8 would advance the reliability of the Bulk-Power System by establishing a uniform modeling framework to improve how IBRs are accounted for in system models and ultimately, the system studies in the operations and planning horizons that rely on those models. The proposed Reliability Standards would also improve how DERs including both IBR-DER and other forms of distribution-connected generating resources, are accounted for in system models when such resources can impact Bulk-Power System reliability. The proposed Reliability Standards address several Commission directives in Order No. 901 related to IBR data sharing and modeling, as well as several findings and recommendations from NERC reports and lessons learned on past Bulk-Power System events.

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:[8]

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III. REGULATORY BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[9] 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 Electric Reliability Organization ("ERO") that would be charged with developing and enforcing 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.[10] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[11] 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

[8] 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.

[9] 16 U.S.C. § 824o.

[10] *Id.* § 824(b)(1).

[11] *Id.* § 824o(d)(5).

mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to make effective.[12]

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.[13]

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.[14] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[15] In its ERO 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.[16] 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.

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12 18 C.F.R. § 39.5(a).

13 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

14 Order No. 672, *supra* note 7, at P 334.

15 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/Pages/Rules-of-Procedure.aspx.

16 ERO Certification Order, *supra* note 3, at P 250.

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 DATA SHARING AND MODELING STANDARDS ADDRESSING INVERTER-BASED RESOURCES AND DISTRIBUTED ENERGY RESOURCES

A. History of the MOD-032 Reliability Standard

Models provide the foundation of virtually all power system studies used to assess the reliability of the Bulk-Power System. Power system studies rely on models to predict system performance under various conditions. Calculation of operating limits, planning studies for assessments of new generation and load growth, and performance assessments of system integrity protection schemes are examples of studies that depend on accurate mathematical representations of transmission, generation, and load. If models are too optimistic, it could result in grid under-investment, unsafe operating conditions, and power outages. If models are too pessimistic, it could result in overly conservative grid operation and under-utilization of network capacity. It is therefore important that models, including all the data to populate the model parameters, are complete, accurate, and up to date.

NERC developed currently effective Reliability Standard MOD-032-1 in 2013-2014 to establish consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability the interconnected transmission system. In developing Reliability Standard MOD-032-1 and the model validation standard Reliability Standard MOD-033-1, NERC considered Commission directives from Order No. 693 addressing modeling responsibilities, [17] directives from Order No. 890 addressing the

[17] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218 (2007), at PP 1178, 1183, 1197, 1210, 1211, 1220, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

periodic review and modification of models to ensure that they are up to date,[18] and NERC committee recommendations to improve upon and streamline the modeling standards.[19] Reliability Standard MOD-032-1 improved upon and consolidated several then-existing MOD Reliability Standards addressing data requirements and reporting procedures for power system models for use in reliability studies.

Reliability Standard MOD-032-1 is intended to provide clear expectations as to who provides what data to whom while also providing entities with flexibility to develop data requirements and reporting procedures that are appropriate to their specific circumstances and Interconnection. The standard consists of the following framework:

- Requirement R1 requires Planning Coordinators and Transmission Planners to jointly develop data requirements and reporting procedures for steady-state, dynamics, and short circuit modeling data for entities in their planning area.

- Requirement R2 requires the registered entities that have the modeling data (i.e., data owners) to provide their data to their Planning Coordinator(s) and Transmission Planner(s) in accordance with the data requirements and reporting procedures developed pursuant to Requirement R1.

- Requirement R3 provides Planning Coordinators and Transmission Planners an opportunity to coordinate with the data owners to address any technical concerns with the data provided under Requirement R2.

- Requirement R4 obligates Planning Coordinators to make available models for its planning area reflecting the data provided to it under Requirements R2 to the ERO, or its designee, for use in creating the Interconnection-wide cases.

The Commission approved Reliability Standard MOD-032-1 in 2014.[20]

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[18] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 at P 290 (2007), *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[19] Additional information on these directives and recommendations and how NERC considered them in the development of Reliability Standards MOD-032-1 and MOD-033-1 is available in NERC's *Petition for Approval of Proposed Reliability Standards MOD-032-1 and MOD-033-1*, Docket No. RD14-5-000 (Feb. 25, 2014).

[20] *N. Am. Elec. Reliability Corp.*, Docket No. RD14-5-000 (May 1, 2014) (delegated letter order). In this order, the Commission also approved Reliability Standard MOD-033-1, the retirement of then-effective Reliability Standards MOD-010-0 and MOD-012-0, and the withdrawal of four MOD Reliability Standards for which the Commission took no action in Order No. 693.

B. History of the IRO-010 and TOP-003 Reliability Standards

The IRO-010 and TOP-003 Reliability Standards help ensure that the functional entities responsible for planning, monitoring, and assessing their areas of the Bulk-Power System have the data and information necessary to perform those responsibilities. The TOP-003 Reliability Standard contains requirements for the development, distribution, and satisfaction of Balancing Authority and Transmission Operator data specifications, while the IRO-010 Reliability Standard contains requirements for the development, distribution, and satisfaction of Reliability Coordinator data specifications.

The Commission first approved the TOP-003 Reliability Standard in 2007[21] and the IRO-010 Reliability Standard in 2011.[22] Since their initial approvals, both Reliability Standards have been revised multiple times. The Commission approved the currently effective versions of the standards, Reliability Standards IRO-010-5 and TOP-003-6.1, in 2023.[23] The currently effective versions reflect a series of enhancements to improve the approaches used for data and information specification and exchange.

Additionally, the Commission approved a future enforceable version of the TOP-003 standard, Reliability Standard TOP-003-7, in February 2025.[24] This version will add Near-Term Energy Reliability Assessments to the list of activities in Requirements R2 for which Balancing Authorities must have documented data specifications and would ensure Balancing Authorities can obtain the necessary data to perform those assessments. Reliability Standard TOP-003-7 will

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21 *Mandatory Reliability Standards for the Bulk-Power Sys.*, Order No. 693, 118 FERC ¶ 61,218, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

22 *Mandatory Reliability Standards for Interconnection Reliability Operating Limits*, Order No. 748, 134 FERC ¶ 61,213 (2011).

23 *N. Am. Elec. Reliability Corp.*, Docket No. RD23-6-000 (Nov. 2, 2023) (delegated letter order).

24 *N. Am. Elec. Reliability Corp.*, Docket No. RD25-5-000 (Feb. 26, 2025) (delegated letter order).

become enforceable on October 1, 2026 in the United States.

C. NERC Identifies the Need to Revise the Reliability Standards Modeling Framework to Address the Growth of BPS-Connected IBRs and Distributed Energy Resources

In late 2021, NERC received a series of Standard Authorization Requests to revise Transmission System planning requirements to address the growth of IBRs on the Bulk-Power System, as well as the growth of resources connected to the distribution system potentially impacting Bulk-Power System reliability.

In December 2021, the NERC System Performance Impacts of Distributed Energy Resources Working Group (or "SPIDERWG") submitted two Standard Authorization Requests, each seeking to improve how Planning Assessments account for the potential impacts of distribution-connected generating resources on the planning, operation, and design of the Bulk-Power System. One Standard Authorization Request sought revisions to the MOD-032 standard to address gaps in data collection for the purposes of modeling aggregate levels of such resources in planning assessments, as well as a review to assign responsibilities to the Distribution Provider following the removal of the Load-Serving Entity as a functional entity registration category.[25] The second Standard Authorization Request sought revisions to the TPL-001 transmission planning Reliability Standard to consider the impacts of these resources in planning assessments.

Also in December 2021, the NERC Inverter-Based Resource Performance Task Force (or "IRPTF") submitted a Standard Authorization Request seeking to revise the TPL-001 Reliability Standard to provide clarity and consistency for how Bulk-Power System connected IBRs are considered, modeled, and studied in transmission planning assessments.

[25] The Commission approved the removal of the Load Serving Entity as a functional entity registration as part of NERC's Risk-Based Registration Initiative in 2015. *N. Am. Elec. Reliability Corp.*, 150 FERC ¶ 61,213 (2015) (approving initiative and directing compliance filing).

To address these Standard Authorization Requests, NERC initiated Project 2022-02 with the project name Modifications to TPL-001-5.1 and MOD-032-1. While work was underway to revise Reliability Standard MOD-032-1, 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 data and modeling issues. These orders are summarized in the following sections.

D. 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,[26] 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 ("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."[27] 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.[28] The Commission directed

[26] Order No. 901, *supra* note 5.

[27] *Id.* at P 25.

[28] *Id.* at Section III, Need for Reform.

NERC to develop new and revised Reliability Standards to address the following four topic areas of IBR issues: (1) data sharing;[29] (2) data and model validation;[30] (3) planning and operational studies;[31] and (4) performance requirements.[32]

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 owned by entities currently registered with NERC for compliance purposes, or would be in the future based on revised registry criteria ("registered IBRs");[33] IBRs that are owned by entities not registered with NERC ("unregistered IBRs") but 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").[34] 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.[35]

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29 *See id.* at PP 66-109 (discussing directives related to data sharing requirements).

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

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

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

33 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). 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 (BES) 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).

34 Order No. 901, *supra* note 5, at P 4 n.14.

35 *Id.* at P 222.

2. Order No. 901 Directives Relating to the Modeling Framework for IBRs

In Order No. 901, the Commission directed NERC to develop new or revised Reliability Standards to support accurate modeling of IBRs, including requirements addressing IBR data sharing, IBR model submissions, and requirements addressing validation of system models against actual system behavior. This filing addresses Order No. 901 directives related to IBR data sharing and model submissions, which are summarized below.

a) IBR-Specific Modeling Data and Parameters

Finding that the sharing of IBR modeling data is critical to ensuring that Bulk-Power System planners and operators are able to plan for, operate, and reliably integrate IBRs onto the Bulk-Power System, the Commission directed NERC as follows:

> Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information, and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System.[36]

Acknowledging comments in the rulemaking proceeding, the Commission further directed NERC to consider specifying data sharing requirements from Transmission Owners to Generator Owners and Generator Operators as part of addressing the above data-sharing directive, while acknowledging that existing processes may already address such sharing.[37] The Commission also directed NERC to consider whether additional IBR data points, beyond those directed to facilitate

[36] *Id.* at P 76.

[37] *Id.* at P 77 (citing comments).

IBR disturbance monitoring and analysis, are needed to further enhance real-time visibility of Bulk-Power System Operations.[38]

In addition to the above-listed directives related to registered IBRs, the Commission also directed the development of new or revised Reliability Standards addressing the provision of accurate modeling data and parameters regarding "unregistered IBRs" and IBR-DERs. NERC and other commenters noted that without all of the relevant protections and controls for these resources being modeled and validated, the resulting studies would not identify possible performance issues.[39] However, there was concern in the underlying proceeding about which entity would be the appropriate entity to provide such data, where the IBR was owned by an entity not subject to compliance with NERC Reliability Standards. Considering the comments, the Commission directed as follows:

> [W]e direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System.[40]

In so directing NERC, the Commission considered that there may be circumstances where Transmission Owners are unable to gather accurate data or parameters, or unable to gather data at all, to create and maintain models for the "unregistered IBRs" in their areas. In such circumstances,

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[38] *Id.* at P 86 (citing comments). NERC previously addressed the Commission's Order No. 901 directives regarding the collection and sharing of IBR disturbance monitoring data in the Order No. 901 Milestone 2 projects described in Section V.

[39] *See id.* at P 91 (summarizing comments of NERC, among others).

[40] *Id.* at P 102.

the Commission directed NERC to develop new or modified Reliability Standards that would instead require Transmission Owners to provide Bulk-Power System planners and operators "(1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation."[41] In directing NERC, the Commission recognized the limitations of estimated data, but stated, "on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the reliability of the Bulk-Power System."[42] The Commission further directed NERC to consider commenter suggestions "to implement a process or mechanism by which transmission owners would receive modeling data and parameters."[43]

Similarly, the Commission recognized concerns that Distribution Providers may not be able to gather adequate modeling data and parameters from IBR-DERs in the aggregate. The Commission therefore directed NERC to include estimation provisions in any new or modified Reliability Standard for IBR-DER data in the aggregate similar to those for "unregistered IBR" data, and to consider commenter suggestions regarding a process or mechanism by which distribution providers would receive modeling data and parameters.[44]

To address compliance concerns as well as comments to specify the data to be submitted by all IBRs, the Commission directed NERC "to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners,

41 *Id.* at P 104.

42 *Id.*

43 *Id.*

44 *Id.* at P 105.

transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear."[45]

b) Use of Approved Industry Generic Library IBR Models

The Commission directed NERC to "require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models."[46] The Commission stated that a responsive standard "could reference the NERC approved component model list which defines the models that may be used, and those models that may not be used, for specific types of studies."[47] The Commission stated, "Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."[48]

In declining suggestions to allow the use of user-defined models, the Commission stated, "the risks associated with the use of user-defined models in the interconnection context are substantially different than in the Bulk-Power System operations and planning context."[49] The Commission stated that:

> In the event of non-convergence or other problems with the model, a user-defined model, if not appropriately parameterized and not submitted with open-source code or dynamic link library and code files, may not allow internal model components to be viewed or modified, which would impede the ability of planning coordinators,

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45 *Id.* at P 108.

46 *Id.* at P 108, 122.

47 *Id.* at P 122. The Commission referenced a document titled the *NERC Standardized Powerflow Parameters and Dynamics Models*, a document created in 2015 as a predecessor to the current Unacceptable Models List.

48 *Id.*

49 *Id.* at P 123.

> transmission planners, transmission operators, and balancing authorities to remediate any issues.[50]

While stating that user-defined models may be appropriate for studying individual transmission systems, the Commission further stated,

> [T]he use of a standard set of approved industry generic library models is essential to creating Bulk-Power System planning and operations system models (i.e., combining models between neighboring entities and for interconnection-wide models) so that Bulk-Power System planners and operators can adequately predict behaviors and subsequent impacts to the reliable operation of the Bulk-Power System.[51]

The Commission directed NERC to determine through its standards development process "which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies"[52] and to "require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models."[53]

c) Submission of Dynamic Models Representing the Dynamic Performance of IBRs

With respect to the submission of dynamic models, the Commission directed NERC:

> [T]o require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior.[54]

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50 *Id.*

51 *Id.*

52 *Id.* at P 124.

53 *Id.* at P 125.

54 *Id.* at P 141.

Where Transmission Owners are unable to gather accurate "unregistered IBR" data or are unable to gather data at all, the Commission directed NERC to require Transmission Owners to provide dynamic models of "unregistered IBRs" using estimated data in accordance with the estimation framework previously directed.[55]

Similarly, the Commission directed NERC to require Distribution Providers to provide aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, using estimated data if necessary.[56] The Commission further directed that, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but have no associated Distribution Provider, that NERC determine the appropriate registered entity responsible for providing data and maintaining the dynamic models.[57] Last, the Commission directed NERC to "ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System."[58]

d) Use of the DER_A Model

With respect to IBR-DERs, the Commission stated that the DER_A model represents "an appropriate basis on which to develop new or revised modeling standards for IBR-DERs."[59] Citing the 2015 *NERC Standardized Powerflow Parameters and Dynamics Models* document, as well as six Reliability Guidelines on the use of the DER_A model, the Commission directed NERC to develop standards that:

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55 *Id.*

56 *Id.*

57 *Id. See also id.* at P 157 (reiterating directive in the context of directives addressing validation of verified IBR models against actual system behavior).

58 *Id.*

59 *Id.* at P 144.

> [R]equire the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to be able to perform respective system studies.[60]

e) Development of a Uniform Modeling Framework

In addition to the above-listed directives addressing IBR data and model sharing, the Commission directed NERC to establish a framework for coordinating and keeping up to date the verified data and models of registered IBRs, "unregistered IBRs", and IBR-DERs in the aggregate in system models. Citing a need for improved coordination when creating and updating planning, operational, and Interconnection-wide data and models, the Commission directed as follows:

> Pursuant to section 215(d)(5) of the FPA,… we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model. Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these resources in the system models. For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives. NERC may implement this

[60] *Id.* at P 146.

> directive by modifying Reliability Standards MOD-032-1 and MOD-033-2 or by developing new Reliability Standards to establish requirements mandating an annual process to coordinate, validate, and keep up-to-date the transmission planning, operations, and interconnection-wide models.[61]

f) Orderly and Timely Implementation of Directed Standards

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."[62]

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.[63] NERC detailed how it will leverage the multiple standards development projects 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

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61 *Id.* at P 161 (citations omitted).

62 *Id.* at P 226.

63 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].

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 (completed: 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)

Work under Milestone 2 of NERC's Order No. 901 Work Plan was completed on November 4, 2024, with the development of the following Reliability Standards and definitions:

- Definition of Inverter-based Resource (IBR), for inclusion in the Glossary of Terms used in NERC Reliability Standards, approved by the Commission in February 2025;[64]
- Reliability Standards PRC 028-1 (Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources) and PRC-002-5 (Disturbance Monitoring and Reporting Requirements), approved by the Commission in February 2025;[65]
- Reliability Standards PRC-024-4 (Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers), Reliability Standard PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-Based Resources), and the definition of the term Ride-through, approved by the Commission in July 2025;[66] and
- Reliability Standard PRC-030-1 (Unexpected Inverter-Based Resource Event Mitigation), approved by the Commission in February 2025.[67]

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64 *N. Am. Elec. Reliability Corp.*, 190 FERC ¶ 61,098 (2025).

65 *Id.*

66 Order No. 909, *Reliability Standards for Frequency and Voltage Protection Settings and Ride-Through for Inverter-Based Resources*, 192 FERC ¶ 61,076 (2025) (approving standards and directing NERC to clarify documentation obligations, to submit an informational filing within 18 months of the conclusion of the ride-through exemption request period in Reliability Standard PRC-029-1 Requirement R4 assessing the reliability impacts of the exemptions clause, and to further consider concerns raised about the need for additional exemptions through the standard development process.)

67 *N. Am. Elec. Reliability Corp.*, 190 FERC ¶ 61,098 (2025).

Relevant to this filing, NERC prioritized the following standards development projects to meet the goals set in Milestone 3 of the Order 901 Work Plan:

- Project 2020-06 Verifications of Models and Data for Generators;
- Project 2021-01 System Model Validation with IBRs; and
- Project 2022-02 Uniform Modeling Framework for IBR.

The standards projects associated with Milestone 3 address the development of a uniform modeling framework for IBR, with requirements addressing the provision of IBR-specific modeling data and parameters, the submission and verification of IBR models to support improved accuracy in system planning, and the validation of system models against actual system performance.

NERC developed the proposed Reliability Standards addressed in this filing, proposed Reliability Standards MOD-032-2, IRO-010-6, TOP-003-8, and the associated definition of Distributed Energy Resource (DER) under Project 2022-02 Uniform Modeling Framework for IBR. As discussed more fully in Section VI, proposed Reliability Standard MOD-032-2 includes requirements addressing data sharing and modeling requirements for IBRs and DERs, consistent with the relevant Commission directives from Order No. 901 and the recommendations of the SPIDERWG. Proposed Reliability Standards IRO-010-6 and TOP-003-8 include revisions to explicitly address the inclusion of IBR data and parameters in Reliability Coordinator, Transmission Operator, and Balancing Authority data specifications and to require that, where models are required, the models submitted for operations planning be consistent with those submitted under the MOD-032 standard. A summary of the Reliability Standards developed to address the Milestone 3 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 Reliability Standard MOD-026-2 – Verification and Validation of Dynamic Models and Data and the defined terms Model Verification and Model Validation for Commission approval. Proposed Reliability Standard MOD-026-2 would consolidate and improve upon two currently effective Reliability Standards governing verification of models and data: Reliability Standard MOD-027-1 - Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions and Reliability Standard MOD-026-1 Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions.

Proposed Reliability Standard MOD-026-2 would advance reliability by ensuring that models used in planning and interconnection analyses, including models representing IBRs, are verified and validated, and that these models accurately represent in-service equipment. In so doing, proposed Reliability Standard MOD-026-2 addresses several Commission directives in Order No. 901 relating to model verification and model accuracy for IBRs.

B. Project 2022-02 Uniform Modeling Framework for IBR

As addressed in this filing, Project 2022-02 Uniform Modeling Framework for IBR proposes three revised Reliability Standards, Reliability Standards MOD-032-2, IRO-010-6, and TOP-003-8, to establish modeling and data sharing requirements that provide sufficient IBR and DER model data and parameters to assure accurate representations of IBR and DER performance within system models. These standards will form the uniform framework for data sharing and model development to support future Order No. 901-related projects.

C. Project 2021-01 System Model Validation with IBRs

Addressed in a separate filing filed concurrently with this petition, Project 2021-01 System Model Validation with IBRs proposes revised Reliability Standard MOD-033-3 – Steady-State and Dynamic System Model Validation. The purpose of this standard is to establish a process for system model validation to facilitate achieving and maintaining model accuracy. Proposed Reliability Standard MOD-033-3 addresses several Commission directives in Order No. 901 related to the validation of IBR models, including the comparison of resulting system models against actual system operational behavior.

Collectively, the proposed Reliability Standards would enhance the reliability of the Bulk-Power System by addressing critical IBR reliability issues in accordance with Milestone 3 of NERC's Order No. 901 Work Plan.

VI. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD MOD-032-2

Models provide the foundation of virtually all power system studies used to assess the reliability of the Bulk-Power System, and it is important that models, including all the data to populate the model parameters, are complete, accurate, and up to date. To date, NERC and the Commission have identified deficiencies in how system models have accounted for IBRs, resources which now comprise a significant part of the grid's resource mix and that have technical and operational characteristics that differ significantly from traditional synchronous generation. Proposed Reliability Standard MOD-032-2 – Data for Power System Modeling and Analysis would advance reliability and improve upon the currently effective MOD-032 standard through requirements intended to ensure that the entities responsible for planning the Bulk-Power System have the data and information they need to build system models that accurately reflect the

performance of IBRs on their portions of the Bulk-Power System, as well as the performance of DERs that can impact Bulk-Power System reliability.

Proposed Reliability Standard MOD-032-2 consists of four requirements, an Attachment 1 describing the information required to effectively model the interconnected transmission system in the near-term and long-term transmission planning horizons, and a new supporting document describing the ongoing process by which NERC will maintain a list of equipment models that structurally do not represent equipment to a suitable fidelity for use in building system models (called the "Unacceptable Models List"). Proposed Reliability Standard MOD-032-2 addresses several Commission directives from Order No. 901 related to the provision of IBR and IBR-DER data and information and improving the quality of submitted IBR and IBR-DER models. As such, it provides an important foundation for completing the operation and planning studies in the Order No. 901 Milestone 4 related standards development projects.

As explained in Exhibit H, 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 31, 2025.

In this section, NERC provides a justification for each component 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 not otherwise addressed in the supporting rationale. Additional information may be found in the Technical Rationale for Proposed Reliability Standard MOD-032-2 included as Exhibit E to this petition, the Complete Record of Development, included as Exhibit H, and the Consideration of FERC Order No. 901 Directives, included as Exhibit D.

A. Title and Purpose

The title and purpose of proposed Reliability Standard MOD-032-2 – Data for Power System Modeling and Analysis remain unchanged from currently effective Reliability Standard MOD-032-1. The stated purpose of the proposed standard is: "To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system."

B. Applicability

Proposed Reliability Standard MOD-032-2 would continue to apply to the Balancing Authority, Generator Owner, Planning Authority/Planning Coordinator, Resource Planner, Transmission Owner, Transmission Planner, and Transmission Service Provider, as in currently effective Reliability Standard MOD-032-1.

Proposed Reliability Standard MOD-032-2 would remove the Load Serving Entity, an applicable functional entity identified in Reliability Standard MOD-032-1. The Load Serving Entity is a functional entity category that is no longer registered for mandatory Reliability Standards compliance purposes.[68] The Distribution Provider[69] was identified as the typical functional entity that would provide the data formerly associated with the Load Serving Entity in Reliability Standard MOD-032-1. Additionally, the Distribution Provider would be an appropriate registered entity to provide information regarding the DERs on its system under proposed Reliability Standard MOD-032-2, consistent with the Order No. 901 directives relating to the

[68] *See* note 25, *supra*.

[69] The Distribution Provider is defined as the entity that "provides and operates the 'wires' between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage." The criteria for registering Distribution Providers is specified in Appendix 5B to the NERC Rules of Procedure, *Statement of Compliance Registry Criteria* (eff. Jun. 27, 2024), available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

provision of such information.[70] Thus, proposed Reliability Standard MOD-032-2 includes the Distribution Provider as an applicable entity.

Following Commission approval of NERC's proposed revised *Glossary* definition of Generator Owner,[71] proposed Reliability Standard MOD-032-2 would apply to a broader category of Generator Owners than those subject to currently effective Reliability Standard MOD-032-1; specifically, the 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.[72] As such, the applicability of proposed Reliability Standard MOD-032-2 is consistent with various directives in Order No. 901 in which the Commission directed NERC to develop IBR data and modeling requirements for "registered IBR generator owners," including Generator Owners owning non-BES IBRs that NERC would register consistent with the IBR Registration Order.[73]

Consistent with paragraph 76 of Order No. 901,[74] the drafting team considered whether to add Generator Operators to the Applicability section of proposed MOD-032-2 and determined that such an addition was not necessary as the Generator Owner oversees the Generator Operator. The

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70 As discussed in Section VI.D, proposed Reliability Standard MOD-032-2 provides flexibility to identify an alternative applicable registered entity to provide such information if there is no registered Distribution Provider for the area.

71 In August 2025, NERC submitted a petition seeking Commission approval of revised definitions of the terms Generator Owner and Generator Operator used in the NERC Glossary. As explained in NERC's petition, the revised definitions are intended to align the definitions of those terms used in NERC Reliability Standards with the revised registration criteria approved by the Commission in 2024. *See Petition of NERC for Approval of Revised Terms "Generator Owner" and "Generator Operator" used in NERC Reliability Standards and Request for Expedited Action*, Docket No. RD25-10-000 (Aug. 27, 2025).

72 *See Order Approving Revisions to N. Am. Elec. Reliability Corp. Rules of Proc. and Requiring Compliance Filing*, 187 FERC ¶ 61,196 (2024).

73 *See* Order No. 901 at 76; *see also* P 4 n.14 (explaining that the Commission intended "IBRs registered with NERC" or similar phrases to include entities both currently registered and those that would be registered under the revised registry criteria).

74 *See* Order No. 901 at P 76 ("Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters…").

Generator Owner may contact the Generator Operator to obtain any information that is needed to satisfy a specification developed under proposed MOD-032-2.

C. Definition of "Distributed Energy Resource"

In conjunction with proposed Reliability Standard MOD-032-2, the Project 2022-02 drafting team developed a proposed definition of Distributed Energy Resource (DER) to provide clarity as to the types of resources for which certain data must be requested and provided under the proposed standard. NERC proposes to define a Distributed Energy Resource (DER) as follows:

> A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

In developing the proposed definition, the drafting team considered various definitions for this term used in the industry, including a working definition developed by the SPIDERWG and definitions used by the Commission and other industry organizations in various contexts. The drafting team also considered the Commission's description of the "IBR-DER" resources for which it was directing NERC to develop new requirements in Order No. 901 ("IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk-Power System.").[75] The drafting team drew on several of these definitions to develop a proposed definition of Distributed Energy Resource (DER) that is sufficiently precise and suitable for defining requirements in Reliability Standards.

The drafting team considered alternative definitions that would not exclude load resources (e.g. energy efficiency and demand response). However, the impact of such load resources is typically reflected in base case load level assumptions rather than requiring explicit modeling

[75] Order No. 901 at P 4 n.14.

within reliability simulations. Thus, including such load resources within the definition of Distributed Energy Resource (DER) would not be suitable for the intended use in Reliability Standards. The phrase "generator or energy storage technology" is intended to capture a wide range of energy sources, including both synchronous resources and IBRs, but excludes devices that only inject Real Power transiently or that are not intended to export Real Power or offset Real Power load. The phrase "in non-isolated parallel operation with the Bulk-Power System" is intended to refer to the types of resources that may impact the reliability of the Bulk-Power System. A resource that is operated only in islanded or isolated mode does not have electrical connectivity to the Bulk-Power System, and it therefore would not have an impact on the reliability of the Bulk-Power System. Last, the phrase "connected to a distribution system" is intended to convey that a Distributed Energy Resource (DER) is a resource that is connected to the distribution system and not the Bulk-Power System; the phase "including one connected behind the meter of an end-use customer that is supplied from a distribution system" clarifies this connectivity includes a resource directly connected to a customer system.

In developing the proposed definition, the drafting team considered including a voltage threshold to define "distribution," but declined to do so for the following reasons. The industry often differentiates transmission from distribution based on the functional use of the system rather than standardized technical specifications. Defining electric facilities as either transmission or distribution is often based on state laws or regulations, Independent System Operator/Regional Transmission Organization tariffs, or utility tariffs. Even though definitions may vary from region to region, there are no conflicts in how applicable entities define distribution and transmission facilities for a given region. The drafting team also considered suggestions to include an active power threshold in the proposed definition. The drafting team declined to do so on the basis that

such technologies can vary in size, and a threshold might inappropriately exclude technologies that are properly considered a Distributed Energy Resource (DER). While the proposed definition is neutral as to size, planning entities may include active power or other entity-determined thresholds in determining which Distributed Energy Resources (DER) to incorporate into planning processes.

D. Requirement R1 and Attachment 1

Proposed Reliability Standard MOD-032-2 Requirement R1 would require each Planning Coordinator and each of its Transmission Planners to jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area. Responsible entities would then be required to provide the data under Requirement R2. Proposed Requirement R1 and the referenced Attachment 1 reflect several improvements intended to improve how planning entities collect data and information regarding the IBRs and Distributed Energy Resources in the planning area, so that the impacts and performance of these resources can be better reflected in system models and thus the planning studies that rely on those models. These improvements are discussed below.

1. Requirement R1

Proposed Requirement R1 would provide as follows:

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include:

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

• standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);

• user-defined models; or

• both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

Proposed Requirement R1 Part 1.1 would require the inclusion of data listed in Attachment 1, along with the entity responsible for providing each required item. Attachment 1 defines the information that is required to effectively model the interconnected transmission system for transmission planning studies, with three columns addressing data and information needed for steady-state, dynamics, and short circuit analyses. The modifications to Requirement R1 Part 1.1 would require the Planning Coordinator and its Transmission Planners to identify the entity or category of entities responsible for the data items listed in Attachment 1. This modification aligns with changes made to the introductory paragraph in Attachment 1, clarifying that data obligations are established by the Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures. While Attachment 1 continues to specify a "typical" functional entity for providing certain data, the added language in Requirement R1 Part 1.1 would reinforce the authority of the Planning Coordinator/Transmission Planner to request data from the appropriate entities, thereby creating obligations for those entities to provide the requested data, even if those

entities are not the "typical" entities that would provide such data. The drafting team determined that such flexibility would be appropriate after considering multiple stakeholder comments suggesting that the entity best positioned to provide accurate data regarding DERs for which there is no registered Distribution Provider present may vary by planning area.[76]

Proposed Requirement R1 Part 1.2, relating to specifications for data format, level of detail, case types or scenarios to be modeled, and data submission schedules, is carried forward unchanged from the currently effective version. Proposed Requirement R1 Part 1.3, relating to specifications for distributing or posting data requirements and reporting procedures, is also carried forward unchanged.

Proposed Requirement R1 Part 1.4 is a new requirement part that addresses required specifications for dynamic model submissions. Proposed Requirement R1 Part 1.4 includes requirements for the Planning Coordinator/Transmission Planner to specify submission of standard library dynamic models, user-defined models, or both. The phrase user-defined models should be considered interchangeable with user-written models, equipment-specific models, and other such terms. Allowing the specification of standard library models incorporated within modeling software is responsive to Commission concerns about usability, and it would allow Planning Coordinators to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. [77] Proposed Requirement R1 Part 1.4 also provides the Planning

[76] *See* Order No. 901 at P 141 (directing NERC to determine which entity should provide data and models for IBR-DER where no registered Distribution Provider is present through the standard development process). *See also* Technical Rationale, Exhibit E at 6 (discussing how the drafting team considered stakeholder comments).

[77] *See* Technical Rationale, Exhibit E at 7. Additional information regarding the Milestone 3 workshops is available on the NERC Standards in Development page, https://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx.

Coordinator/Transmission Planner with the authority to require submission of both model types. Proposed Requirement R1 Part 1.4.2.1 would require each Planning Coordinator and Transmission Planner accepting user-defined models to provide their user-defined model requirements to other Planning Coordinators and Transmission Planners within the Interconnection upon request.

In Order No. 901, the Commission directed NERC to "determine…which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies" and to develop Reliability Standards that would require the "use of approved industry generic IBR models."[78] The Commission also directed NERC "to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models."[79]

In considering how to address the directive regarding the use of approved industry generic IBR models, the drafting team considered that the practical considerations and timelines associated with maintaining a pre-approved model library could conflict with broader objectives to have accurate models, particularly as IBR technology rapidly progresses. The ERO does not presently maintain an "acceptable model library," defining all acceptable models, but rather an "unacceptable model library," identifying models for which issues have been identified. Given the pace of technological development, it may prove difficult to both develop and maintain an approved generic model library in a timely fashion. The approach taken in proposed Reliability Standard MOD-032-2 specifying the use of standard library component models approved and offered by software simulation tools, along with a backstop against the unjustified use of models

[78] Order No. 901 at P 124. *See also id.* at P 108 ("As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions.")

[79] *Id.* at P 125.

determined to be generally unsuitable (*see* discussion of the Unacceptable Model List in Requirement R2 below), would ensure that models used in Interconnection-wide analysis are robust enough while accuracy is not compromised to any level of detail deemed necessary.

In considering the Commission's directive to require the "sole use" of approved generic models, the drafting team determined to employ an equally effective and efficient approach for addressing the underlying reliability concern. The drafting team understood the overarching goal of this directive would be to obtain IBR models that are accurate and usable by Planning Coordinators/Transmission Planners for building their Interconnection-wide models and planning cases. The drafting team considered that many entities have a different understanding for what is a "generic model," and that NERC as the ERO does not presently maintain a comprehensive list of approved generic models. The drafting team further considered that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 while offering more accurate representations of IBR behavior and characteristics. Therefore, in addressing this directive, the drafting team determined to build upon the modeling framework discussed above to allow Planning Coordinators to specify submission of generic models, user-defined models, or both. Where user-defined models are allowed, the Planning Coordinator/Transmission Planner must specify usability requirements. These usability requirements, which must include, at a minimum, requirements to provide model documentation and instructions for model set up and use, would address issues that are typically associated with user-defined models such as non-convergence. To ensure that there is transparency in building the Interconnection-wide cases, the Planning Coordinator/Transmission Planner must provide its user-defined model usability requirements to other Planning Coordinators/Transmission Planners within the Interconnection upon request. The drafting team concluded that this approach would

balance the practical limitations of "generic models" raised by industry with the need for an improved uniform modeling framework that accurately reflects the behavior and characteristics of IBRs in Order No. 901. This approach would also maintain flexibility to accommodate the rapid pace of technological change.

2. Attachment 1

Attachment 1 to the proposed standard, referenced in Requirement R1, defines the information that is required to effectively model the interconnected transmission system for transmission planning studies. Attachment 1 has three columns addressing data and information needed for steady-state, dynamics, and short circuit analyses.

As an initial matter, proposed Attachment 1 would replace all references to the Load-Serving Entity as a typical entity responsible for providing certain data with the Distribution Provider. This includes data regarding aggregate demand, static VAR systems and flexible alternating current transmission systems (FACTS), and other data as needed. This change is consistent with the revised Applicability of the proposed standard discussed above. Proposed Attachment 1 also reflects revisions corresponding to proposed Requirement R1 Part 1.1, to specify that while typical responsible entities are identified for each data item, the Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures will specify entity responsibility and data flow processes.

Proposed Attachment 1 reflects several revisions to improve data that is collected for IBRs, including Bulk-Power System connected IBRs owned by Generator Owners registered with NERC for mandatory compliance purposes (referred to as "registered IBRs" in Order No. 901) and Bulk-Power System IBRs that fall below the threshold that would require the owner to register with NERC (referred to as "unregistered IBRs" in Order No. 901). Proposed Attachment 1 also reflects

several revisions to improve the data collected for DERs, including IBR-DER and other DER, that in the aggregate can affect the reliability of the Bulk-Power System.

These revisions address the Commission's directive in paragraph 78 to "establish uniform, minimum categories or types of data that must be provided so that Bulk-Power System planners and operators can predict the behavior of all IBRs,"[80] as well as its directive in paragraph 108 to "determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear."[81] The revisions, which are shown in redline in Exhibit A-1, are discussed below.

a) IBR Data

To improve Attachment 1 as it relates to IBR data, the drafting team revised steady-state column, item 3 to include data on storage units as well as generating units. The term "generating unit" already includes IBR generators such as solar and wind. The drafting team determined to add storage explicitly because storage is typically not classified as a generation resource because it has no primary energy source and consumes more energy than it injects when considering losses. Proposed footnote 4 clarifies that generating and storage units would include IBRs and synchronous condensers.

In the dynamics column, the drafting team replaced the phrase "photovoltaic systems" with "Inverter-Based Resources" in item 7. IBR is a more encompassing term that includes photovoltaic systems. Under 7.a, the drafting team specified the type or data that must be included. The first

80 *Id.* at P 78.

81 *Id.* at P 108.

three, IBR parameters, settings, or capabilities related to momentary cessation, tripping, and ride-through, were added in consideration of the Commission's directive in Order No. 901 paragraph 141.[82] The addition of parameters, settings, or capabilities related to voltage control was added in recognition of the importance of voltage control performance for normal and post-disturbance operations.[83] The addition of parameters, settings, or capabilities related to frequency control was added because frequency response of IBR is important for studying system reliability.[84]

Dynamics item 6 is revised to refer to type 1 and type 2 wind turbines, which are not IBR, to avoid overlap with new IBR item 7.

Proposed footnote 5 indicates that the Planning Coordinator/Transmission Planner data requirements and reporting procedures need to account for what Order No. 901 identified as "unregistered IBRs"; in footnote 5, these IBRs are described as "IBRs that are not DERs and do not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes". Proposed footnote 5 also indicates that the Transmission Owner is the entity that would typically be responsible for providing such data, consistent with Order No. 901 paragraph 102.[85]

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[82] *Id.* at P 141 ("We also direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators…dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior.")

[83] *See* Technical Rationale, Exhibit E at 10 (citing NERC*, IBR Performance and Modeling, Level 3 Alert*. May 2025, https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/Level%203%20Alert%20Essential%20Actions%20IBR%20Performance%20and%20Modeling.pdf)

[84] *See* Technical Rationale, Exhibit E at 10 (citing NERC, *Lessons Learned: Incorrect IBR Primary Frequency Response Logic Caused Negative ACE*, https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20240501_Incorrect_IBR_Primary_Frequency_Response_Logic_Caused_Negative_ACE.pdf).

[85] Order No. 901 P 102 ("[W]e direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System…").

b) DER Data

To improve Attachment 1 as it relates to DER data, new item 9 in the steady-state column addresses aggregate DER data, including location, Real Power capability, and DER type as required items. The drafting team selected these three items as the minimum information needed to use data and make assumptions for power system modeling and analysis, but the Planning Coordinator/Transmission Planner have the authority to request additional data items as deemed necessary. Notably, while Order No. 901 refers to data from "IBR-DER in the aggregate,"[86] the drafting team determined that proposed Reliability Standard MOD-032-2 should address all DER regardless of type. This change is consistent with one of the original Standard Authorization Requests initiating Project 2022-02 to improve how DER is reflected in system models and planning studies.

"Aggregate DER" is specified in steady-state column item 9 to indicate that aggregate DER data, rather than individual DER facilities, would be represented in most Planning Coordinator/Transmission Planner study models. This is consistent with Order No. 901 which required data and modeling of at a minimum "IBR-DER *in the aggregate*".[87] Required items include location, real power capability, and DER type. In certain circumstances, such as in the case of a large DER, the Planning Coordinator/Transmission Planner may decide to represent the individual DER given the potential impacts on the Bulk-Power System.

In the dynamics column, three items were updated, consistent with the Order No. 901 directive to "ensure that the proposed new or modified Reliability Standards account for the

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[86] *See, e.g.*, *id.* ("[W]e direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require:… (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System.")

[87] *See id.* (emphasis added).

dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System."[88] First, item 5, previously "demand", was updated to be "aggregate demand" to be consistent with the steady state column and general industry practices of modeling load dynamics for aggregate demand (e.g., composite load model). Second, Dynamics item 10 was updated to include "Aggregate Distributed Energy Resource (DER) data" along with the subitems: "parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control"; and "indication whether DERs are subject to tripping in conjunction with UFLS or UVLS". As explained in the Technical Rationale, information regarding momentary cessation, tripping, and ride-through of aggregate DERs is needed for dynamics studies; this inclusion is also consistent with paragraph 141 of Order No. 901.[89] Voltage control of DERs can alter the exchange of reactive power between distribution and transmission systems and may affect the results of reliability studies.[90] Frequency control must be accounted for because DER interconnections under different standards have different frequency response characteristics that may affect dynamics study results. Last, accurately representing DER tripping as part of UFLS or UVLS operation is necessary for designing and evaluating UFLS or UVLS programs. Third, item 10 in the dynamics column indicates that aggregate DER dynamics modeling data (parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control) may need to be inferred due to data availability and

88 *Id.* at P 141.

89 *See* Technical Rationale, Exhibit E at 12 (citing NERC's Lessons Learned, LL20220401 "Distributed Energy Resource Performance Characteristics during a Disturbance"). *See also* Order No. 901 at P 141 ("Further, we direct NERC to require distribution providers to provide…aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior.")

90 *See id.* at 12.

practical limitations. Further considerations for inferring data are described in the Technical Rationale.[91]

Proposed Attachment 1 also reflects several revisions and improvements in the table footnotes.

First, proposed footnote 3 associated with "aggregate demand" is modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DERs is not consistent with a modeling framework that explicitly represents DERs. The proposed footnote also clarifies that this calculation may be impacted by an aggregation threshold for DER specified by the Planning Coordinator/Transmission Planner.

Second, proposed footnote 6 identifies that the Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. Proposed footnote 6 also provides that the Transmission Owner would be the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system. This footnote addresses Order No. 901 paragraphs 102 and 108, requiring Distribution Providers to provide information regarding DERs in their areas, as well as paragraph 106, relating to the appropriate registered entity to provide information regarding DERs where there is no registered Distribution Provider responsible for providing the information.[92] This

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91 Technical Rationale, Exhibit E at 12-13.

92 *See* Order No. 901 at PP 102, 106, and 108.

footnote also addresses similar aspects of the directives in paragraph 141 and 157.[93] While the proposed footnotes identify the "typical" entities for providing such data, the Planning Coordinator/Transmission Planner would have the flexibility under revised Requirement R1 to identify the most appropriate entity to provide such data in the planning area. The drafting team determined that such flexibility would be appropriate after considering comments during the standard development process suggesting that entities other than the Transmission Owner may be better positioned to provide data regarding DER in a given planning area.

Third, proposed footnote 7 clarifies that aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1. The drafting team considered that a determination of whether an "unregistered IBR" or aggregate IBR-DER would materially affect the Bulk-Power System as provided in Order No. 901 would require engineering judgment, and thus specifying precise thresholds in a Reliability Standard may not be appropriate. The NERC DER Modeling Study Report provides considerations for identifying appropriate thresholds for a planning area.[94]

In developing these revisions, the drafting team considered the Order No. 901 paragraph 146 directive to require the use of the DER-A model or successor models to represent the behaviors of IBR-DERs. As explained previously, proposed Reliability Standard MOD-032-2 would require

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[93] *Id.* at P 141 ("Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we…direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models.") *See also id.* at P 157 ("Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models.")

[94] *See* NERC, *DER Modeling Study: Investigating Modeling Thresholds* (Nov. 2022), https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf.

the modeling of aggregate DER data through the revisions to Requirement R1 and Attachment 1. (The provision of estimated data is addressed in Requirement R2, discussed in the following section). The drafting team considered that the currently available DER_A model is sufficient only for positive sequence phasor domain simulations. With the variety of other simulation domains (such as EMT and short circuit) necessary to study IBRs, mandating the use of this model could prevent Planning Coordinators/Transmission Planners from performing their studies. Further, given the pace at which models are rapidly evolving, specifying the use of one particular model or a successor model in a Reliability Standard could ultimately create challenges to accurate modeling. NERC would need to initiate its standard development process to accommodate higher fidelity models that are developed in the future, meaning any changes that could advance the state of modeling might be several years delayed. NERC's proposed framework for modeling in proposed Reliability Standard MOD-032-2 would not specify the use of specific models, models which might quickly become surpassed by better models, but rather define requirements for model quality and accuracy that would allow flexibility in model selection and advance the state of modeling now and into the future. For these reasons, the drafting team considered that its proposed approach represents an equally effective and efficient means of addressing the reliability concern underlying the Commission's directive regarding the use of the DER_A model.

E. Requirement R2

Proposed Reliability Standard MOD-032-2 Requirement R2 establishes requirements for Balancing Authorities, Distribution Providers, Generator Owners, Resource Planners, Transmission Owners, and Transmission Service Providers to provide data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. Proposed Requirement R2 would revise the currently effective

requirement to address the provision of estimated data and the submission of models deemed generally unacceptable for studies as follows:

R2. Each Balancing Authority, Distribution Provider, Generator Owner, ~~Load Serving Entity,~~ Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation;

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

Proposed Requirement R2 would replace the Load Serving Entity with the Distribution Provider, consistent with changes made to the Applicability of the standard and Attachment 1 discussed in previous sections.

Proposed Requirement R2 Part 2.1 is a new requirement part addressing how registered entities would provide estimated data for resources owned by unregistered entities if they are unable to gather the actual data. In Order No. 901, the Commission directed NERC to develop requirements addressing the provision of data related to "unregistered IBRs" and "IBR-DERs in

the aggregate that have a material impact on the BPS."[95] The Commission, however, recognized that NERC registered entities may be unable to gather such data from unregistered entities. Finding that estimated data would represent an improvement upon having no data at all, the Commission directed that NERC develop requirements addressing the provision of estimated data.[96] Similar directives address the provisions of dynamic models using estimated data.[97] Proposed Requirement R2 Part 2.1 would require the entity responsible for providing information regarding "unregistered IBR" or aggregate DER data under a Planning Coordinator/Transmission Planner data specification to estimate such data if it is unable to gather it, and to provide this estimate along with an explanation of the limitations of the estimated data and the method used for estimation to the Planning Coordinator/Transmission Planner. As explained in the Technical Rationale, proposed Requirement R2 Part 2.1 would allow entities flexibility to develop estimates from interconnection documentation, measured quantities, estimated quantities, or other sources. A combination of approaches may be appropriate due to data availability or sufficiency issues. The Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures may identify acceptable methods and their application.[98]

Additionally, and as further explained in the Technical Rationale, proposed Requirement R2 Part 2.1 addresses the estimation of aggregate DER data, regardless of resource type. While Order No. 901 directed NERC to develop requirements addressing the estimation of IBR-DER data in particular, Project 2022-02 was also charged with developing Reliability Standards modifications to improve how DER in general is reflected in system studies. In drafting proposed

95 Order No. 901 at P 161.

96 *Id.* at PP 104, 105, 106.

97 *See id.* at P 141.

98 *See* Technical Rationale, Exhibit E at 7-8.

Reliability Standard MOD-032-2, the drafting team determined to create a consistent estimation framework applicable for all DER technologies when DER data cannot be gathered.[99]

Proposed Requirement R2 Part 2.2 is a new requirement part intended to confirm the relationship between proposed Reliability Standard MOD-032-2 and the separately-filed proposed Reliability Standard MOD-026-2 addressing Order No. 901 directives related to establishing a standard uniform model verification process.[100] The intent of Order No. 901 is to ensure that accurate (i.e. validated and verified) models are collected under proposed Reliability Standard MOD-032-2. However, facility models submitted under the MOD-032 standard are often submitted before physical validation can be completed (e.g., for planned facilities). Proposed Requirement R2 Part 2.2 would require the model submitted by the functional entity be the model that was verified and validated (and accepted by the Transmission Planner) in accordance with MOD-026, if available.

Proposed Requirement R2 Part 2.3 provides that entities providing any model included on the Unacceptable Models List maintained by the ERO shall provide a technical justification supporting its use. The Unacceptable Models List is included as Exhibit F to this petition. The Unacceptable Models List is a successor to the NERC *Acceptable Models List*, which itself was a

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[99] *See id.* at 7-8. As discussed in Section VIII below, NERC is including a Potential Noncompliance Abeyance Period for this requirement in proposed Reliability Standard MOD-032-2 to facilitate close monitoring of the implementation of these estimation provisions.

[100] *See* Order No. 901 at P 143 ("Regarding EPRI's recommendation to require appropriately parameterized plant models, we agree that the model verification process of an IBR model should include steps to ensure that responsible entities provide both verified and appropriately parameterized models. Additionally, we agree with IRC's recommendation that the plant model verification process should include requirements for equipment to be represented as installed in the field. While we decline to include this level of detail in the directive to NERC, we nonetheless direct NERC to establish a standard uniform model verification process. A uniform model verification process will ensure that all entities use the same set of minimum requirements to verify that all generation resource (i.e., synchronous and non-synchronous) models are complete and that the models accurately represent the dynamic behavior of all generation resources at a sufficient level of fidelity for Bulk-Power System planners and operators to perform valid interconnection-wide, planning, and operational studies. Therefore, we direct NERC to define the model verification process and to require consistency among the model verification processes for existing Reliability Standards (e.g., FAC-002, MOD-026, and MOD-027) and any new or modified Reliability Standards.")

successor to the NERC *Libraries of Standardized Powerflow Parameters and Dynamic Models*, a document created in 2015 by the Modeling Working Group of the former NERC Planning Committee[101] which was referenced in Order No. 901.[102] The Unacceptable Models List reflects models that have been identified as having known issues. As noted in Section VI.D discussing proposed Requirements R1 and Attachment 1, the drafting team considered the challenges of maintaining an up-to-date library of approved models in developing MOD-032 requirements responsive to the Commission's directives in Order No. 901. It was determined that a standard that would define both positive attributes for such models, as well as models that should not be used without caution, would represent an equally effective and efficient means of addressing the Commission's directives regarding the use of approved generic models.

Initially, the drafting team proposed to prohibit any use of a model on the Unacceptable Models List. However, the drafting team considered stakeholder comments noting that a model on the Unacceptable Models List may be the best or only available model for some generators, particularly for some synchronous generators and for units manufactured by companies that are no longer in business.[103] Proposed Requirement R2 Part 2.3 would allow for the submission of such a model if accompanied by a technical rationale justifying its use. This technical rationale would help ensure that models with known deficiencies are not being submitted without good reason. This requirement would thereby advance the state of modeling overall consistent with the intent of Order No. 901. This requirement is not intended to supplant the process described in

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101 NERC Modeling Working Group, *NERC Libraries of Standardized Powerflow Parameters and Standardized Dynamics Models* version 1 (Oct. 15, 2015), available at https://www.nerc.com/comm/PC/Model%20Validation%20Working%20Group%20MVWG%202013/NERC%20Standardized%20Component%20Model%20Manual.pdf.

102 *See* Order No. 901 at P 122 n.232.

103 *See* Technical Rationale, Exhibit E at 9.

Requirement R3 by which the Planning Coordinator or Transmission Planner may identify technical concerns with the model or the supporting technical rationale.

NERC proposes to maintain the Unacceptable Models List separately from proposed Reliability Standard MOD-032-2. Maintaining the list separately would allow NERC to make updates more expeditiously than may be possible under the Reliability Standards development process. To balance concerns about due process for mandatory and enforceable elements of Reliability Standards with the need for agility, proposed Reliability Standard MOD-032-2 includes the process by which NERC would update the Unacceptable Models List. This process includes multiple steps intended to ensure fair and open vetting of any proposed changes to the Unacceptable Models List, including the technical basis for such changes.

To update the Unacceptable Models List, a person or entity would submit a detailed change request to NERC identifying the model, the nature of the request (i.e. add model as unacceptable model or remove model as unacceptable model), and technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior. The review process contemplates engagement with the Reliability and Security Technical Committee or other industry subject matter experts in vetting each change request and recommending dispositive action. NERC would provide an opportunity for public comment on any proposed change request. Upon approving any change to the Unacceptable Models List, NERC would provide public notice through an announcement, a posting to the NERC website, and an informational filing to the applicable governmental authorities. This notice would include the effective date for any change, so that entities using models that are added to or removed from the Unacceptable Models List would have notice of when their obligations with respect to the submission of those models would change.

In recognition of concerns raised during the development process for proposed Reliability Standard MOD-032-2, it is NERC's intent that changes to the process for revising the Unacceptable Models List would be made through the standard development process, while changes to the Unacceptable Models List itself would be made according the more agile process specified in Reliability Standard MOD-032-2.

F. Requirement R3

Proposed Reliability Standard MOD-032-2 Requirement R3 addresses the identification of technical concerns with data submitted under Requirement R2. Proposed Requirement R3 would revise the currently effective requirement as follows:

> R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, ~~Load Serving Entity,~~ Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows:
>
> 3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data~~;~~, that is responsive to the technical concern.
>
> 3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

Revisions to replace the Load Serving Entity with the Distribution Provider are consistent with other revisions to the proposed standard discussed in previous sections. The addition of the phrase "responsive to the technical concern" in proposed Requirement R3 Part 3.1 would support the goal of Requirement R3, which is to resolve technical concerns that are identified by the Planning Coordinator or Transmission Planner with submitted data or models. Entities providing models may not always know that their update or explanation will resolve the technical concern. Adding the phrase "responsive to the technical concern" would convey that further information exchanges between the planning and submitted entities may be needed beyond the initial response.

G. Requirement R4

Proposed Reliability Standard MOD-032-2 Requirement R4 is carried forward unchanged from the currently effective standard, as follows:

> R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area.

As discussed more fully in Section VI.H.2, NERC determined that no revisions were needed to this requirement to address the Commission Order No. 901 directives; in particular, the paragraph 161 directive relating to the development of an "annual process to coordinate, validate, and keep-up-to date the transmission planning, operations, and interconnection-wide models."

H. Consideration of Order No. 901 Directives

Proposed Reliability Standard MOD-032-2 is responsive in whole or in part to multiple Commission directives regarding IBR data and models in Order No. 901.[104] In the preceding sections, NERC explained how proposed Reliability Standard MOD-032-2 addressed in whole or in part Commission directives in paragraphs 76, 78, 102, 106, 108, 122, 124, 125, 141, 146, and 157 of Order No. 901. The Commission's directive regarding the implementation of Reliability Standards responsive to its directives (paragraph 226) is addressed in Section IX below.

This section discusses how the drafting team for proposed Reliability Standard MOD-032-2 considered other Commission directives not specifically addressed above, including those in paragraph 77 and 161. Exhibit D provides NERC's consideration of the relevant directives in a directive-by-directive format.

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[104] Order No. 901 at P 85.

1. Paragraph 77 Regarding Consideration of Transmission Owner Data Sharing

In paragraph 77 of Order No. 901, the Commission directed NERC to consider commenter suggestions in the underlying proceeding to add data sharing requirements from Transmission Owners to Generator Owners and Generator Operators.[105] The drafting team considered these suggestions as directed by the Commission. The drafting team determined that such a requirement would not align with the stated purpose of the MOD-032 standard, which is to establish consistent modeling data requirements and reporting procedures for the development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. The drafting team further determined that requests for Transmission Owners to provide data to Generator Owners and Generator Operators are most appropriately addressed through processes that exist outside of the MOD-032 Reliability Standard, and it concurred with the Commission's suggestion in Order No. 901 paragraph 77 that these processes are already in place.

2. Paragraph 161 Regarding the Uniform Modeling Framework

In paragraph 161, the Commission directed NERC to develop new or modified Reliability Standards that:

> [R]equire planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model.

Additional aspects of this directive address verification of data and models.

[105] *Id.* at P 77.

The proposed Reliability Standards discussed in Section V above collectively address the Commission's directive in Order No. 901 paragraph 161. The Project 2022-02 drafting team modified the MOD-032 standard to ensure it captures the uniform framework with modeling criteria and necessary data exchange requirements for registered IBRs, "unregistered IBRs", and DER (to include IBR-DER). Modifications in the TOP-003 and IRO-010 standards, addressed below, are intended to promote consistency in the models submitted for planning purposes and operations purposes so that the entities responsible for planning and operating the Bulk-Power System are all working from similar models that accurately represent the resources within their respective footprints.

A uniform modeling framework is established in the proposed Reliability Standard MOD-032-2 through improvements to Requirements R1, R2, and R3 and Attachment 1, discussed above. The inclusion of the ERO Unacceptable Models List (and the associated revision process) and additional requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. Where appropriate, there is flexibility built into this framework to accommodate differences in planning area modeling needs. The Planning Coordinator/Transmission Planner are allowed to require standard library models, but if user-defined models satisfy usability criteria and the standard's requirements, they are not prohibited. The framework explicitly allows for the submission of standard library models along with submission of user-defined models which allows for the use of standard library models when combining neighboring transmission system models and Interconnection-wide models. If user written models are accepted, the Planning Coordinator/Transmission Planner are required to share their usability criteria with other planning entities within the Interconnection upon request.

The drafting team added specific items regarding IBRs (including "unregistered IBRs") and DER (including IBR-DER) to Attachment 1 of the MOD-032 standard, thereby ensuring their inclusion in Planning Coordinator/Transmission Planner data specifications. While the Transmission Owner would be the typical entity for providing "unregistered IBR" data, and the Distribution Provider would be the typical entity to provide DER data, the drafting team recognized that there may be some variations as to whom might have the most accurate and usable data for unregistered resources in the planning area. Therefore, the drafting team modified the requirement language to provide the Planning Coordinator/Transmission Planner with the flexibility to identify the most appropriate entity to provide the listed data.

The Planning Coordinator/Transmission Planner may also specify DER thresholds that may be appropriate when considering impact on their local areas. A determination if an "unregistered IBR" or aggregate IBR-DER would "materially affect" the Bulk-Power System requires engineering judgment and the consideration of other material factors; the drafting team determined that it would not be prudent to prescribe any specific approach in a Reliability Standard. The drafting team added footnote 7 in Attachment 1 of proposed Reliability Standard MOD-032-2 to allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas.

As discussed more fully in Section VII below, the drafting team also revised the IRO-010 and TOP-003 standards to include IBRs specifically. To the extent IBR modeling data is deemed necessary under the IRO-010 and TOP-003 standards, it should be consistent with modeling data provided for planning purposes. Consistency in models is important to ensure Bulk-Power System planners and operators are working from similar and high quality models; however, the drafting

team recognized that operations entities may require adjustments from the model submitted for planning purposes to satisfy the needs in an operations environment.

NERC considered the fidelity/accuracy components of the Order No. 901 directives to be within the scopes for Projects 2020-06 and 2021-01, rather than Project 2022-02. However, the model framework established with proposed Reliability Standard MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection, so that entities may select the most representative model for the resource meeting Planning Coordinator/Transmission Planner requirements (rather than mandating use of a defined set of models which may quickly become out-of-date). Models that are known to have fidelity issues (i.e. models on the Unacceptable Models List) are not to be submitted without technical justification. Models submitted under proposed Reliability Standard MOD-032-2 shall be the models verified under proposed Reliability Standard MOD-026-2, where available. System models validated under proposed Reliability Standard MOD-033-3 shall be developed in accordance with data provided under proposed Reliability Standards MOD-032-2 and MOD-033-3.

Regarding that part of the directive to keep models up to date, proposed Reliability Standard MOD-032-2 would continue to provide for timely updates by requiring a schedule for submission of data at least once every 13 calendar months. System models would thus be built on updated data and models, which are verified and validated in accordance with the proposed Reliability Standards MOD-033-2 and MOD-026-2.

Regarding that part of the directive addressing a "registered model designee" for building the Interconnection-wide cases, NERC considered the directive and concluded that the present MOD-032 ERO modeling designee framework, with notable enhancements since 2023, presents an equally effective and efficient alternative to designating an entity on the NERC Compliance

Registry to perform the tasks of Interconnection-wide model building. Further, the present framework, with these recent enhancements, has distinct advantages over designating a responsible entity in that it maintains ongoing, forward-looking oversight of the Interconnection case building process, with case quality or process issues addressed as they are identified, rather than compliance or audit-focused oversight of specific entities that by nature has a retroactive focus.

Currently effective Reliability Standard MOD-032-1 Requirement R4 requires each Planning Coordinator to make available models for its planning area provided under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support the creation of the Interconnection-wide cases. This is not changed in proposed Reliability Standard MOD-032-2 Requirement R4. Coordination and fidelity/accuracy concerns, however, are addressed throughout the process, which would result in better and higher quality models being submitted to the ERO or its designee. As noted above, proposed MOD-032-2 Requirement R1 Part 1.1 would require the Planning Coordinator/Transmission Planner to identify the entity responsible for each required item in Attachment 1, including the newly added items for IBR and DER. The entity must then provide the information in accordance with Requirement R2. A new Requirement R2 Part 2.2 has been added to require that if the entity is required to provide dynamic models, that these be the models accepted by the Transmission Planner under MOD-026, if available. This provision would provide for a clearer link between the two standards and facilitate coordination and model updates needed by registered entities. Proposed Reliability Standard MOD-032-2 Requirement R3 would continue to serve to address technical concerns with the data submitted under Requirement R2.

As to which entity builds the Interconnection-wide base case model, the ERO has designated entities with a sufficient wide area view and focus on reliability for each Interconnection to perform this work. For the Texas Interconnection, the Texas Regional Entity

performs this work in coordination with ERCOT. For the Western Interconnection, the Western Electric Coordinating Council (WECC) performs this work. For the Eastern Interconnection, the Eastern Interconnection Reliability Assessment Group (ERAG), consisting of Regional Entities Midwest Reliability Organization (MRO), Northeast Power Coordinating Council, Inc. (NPCC), ReliabilityFirst (RF), and SERC Reliability Corporation (SERC), performs this work.[106] The ERAG also performs the base-case model creator function for the Quebec Interconnection in Canada. NERC facilitates the group of Regional Entity staff who are responsible for designated entity activities. This group meets periodically to discuss case quality metrics and to improve the Interconnection case-building process.

As the ERO, NERC is responsible for overseeing and ensuring that these designated entities perform their activities in a satisfactory manner. In 2023, the Officers Leadership Team of the ERO Enterprise approved the MOD-032 Designee process document. This process document reflects the maturation of this aspect of the ERO's activities and contains clauses and processes that require the designee for the Interconnection to perform specific duties. Each designee must have certain attributes, including a governance structure responsive to the needs of Planning Coordinators, with clear roles and responsibilities for model creation, transparency in data requirements, establishing timeframes for review cycles, and defining security and access to models. This process document is very much a "living document," intended to be reviewed each year as part of coordinated ERO Enterprise assessments under the Regional Delegation

[106] Regarding the ERAG, there is also an Eastern Interconnection Regional Entity Agreement among MRO, NPCC, RF, and SERC. In this agreement, there are provisions for oversight and coordination in how this group exercises its authority as the MOD-032 designee. Additional information on the Eastern Interconnection Regional Entity Agreement is available at https://www.rfirst.org/wp-content/uploads/2025/10/Eastern-Interconnection-Regional-Entity-Agreement.pdf.

Agreements and updated as needed to help ensure that the process is responsive to the needs of the grid.[107]

The process requires the MOD-032 designee to develop certain core cases, including core cases for the ERO for use in seasonal planning studies and event analyses. Other core cases are required for validating Interconnection Frequency Response obligations and event analyses. The process also requires the development of typical cases to support implementation of the TPL-001 standard. NERC or the Regional Entities may request additional specialized cases as needed.

Designated entities have certain responsibilities under this process, which includes several controls to ensure quality. Designated entities are responsible for collecting data from all Planning Coordinators. They are also responsible for developing and maintaining a case creation manual including the process by which cases must be assembled, tested for quality, and tested for case fidelity according to ERO case quality metrics. NERC performs an annual case quality assessment tracking the quality of the base cases created by the MOD-032 designated entities for the purposes of Interconnection-wide modeling and subsequent system studies.[108] The designated entity is responsible for having a process to address any case quality deficiencies identified by NERC.

Additionally, the designated entity must have a process to incorporate improvements identified in NERC's independent modeling assessments. Each designated entity must have a process for addressing recurring data or model errors found during case creation or quality and validation testing with Planning Coordinators, as well as a process for correcting cases for current or future years created in the latest case creation cycle that are already in use.[109] Examples of

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[107] To aid the Commission in understanding how NERC has considered this directive in developing proposed Reliability Standard MOD-032-2, NERC is filing, for informational purposes, the current version of the MOD-032 Designee Process Document as Exhibit D-1.

[108] *See, e.g.*, NERC, *Case Quality Metrics: Annual Interconnection-Wide Model Assessment* (Nov. 2024), available at https://www.nerc.com/pa/RAPA/ModelAssessment/Pages/default.aspx.

[109] For more information, see Consideration of Order No. 901 Directives, Exhibit D at 28-29.

processes maintained by the designated entities for carrying out their responsibilities are publicly available on their respective websites.[110]

Collectively, the revisions in the proposed suite of Milestone 3 Reliability Standards are expected to improve the quality of information provided to Planning Coordinators/Transmission Planners, particularly for IBRs and DERs, and thus the quality of models submitted to the ERO under Reliability Standard MOD-032-2 Requirement R4 for building the Interconnection-wide cases. These standards improvements are expected to address critical IBR-related issues that NERC has identified in previous case quality assessments. Nevertheless, NERC will continue to oversee the development of the Interconnection-wide cases and report on case quality metrics consistent with the MOD-032 Designee process document. To the extent NERC or the MOD-032 designated entities identify that further refinements to the MOD-032 standard are needed to ensure that model quality issues are addressed in a timely manner, NERC will consider them through its standard development process at that time.

In summary, the proposed revisions to the MOD-032, MOD-033, and MOD-026 Reliability Standards addressed in NERC's Order No. 901 Milestone 3 work, along with the ERO designated entity framework discussed above for building Interconnection-wide cases, address the concerns underlying the Commission's directive in paragraph 161 of Order No. 901 regarding the coordination, updating, and timely development of quality Interconnection-wide models that accurately represent the behavior of IBRs in the Interconnection. Further, this framework advances consistency in modeling used across planning and ERO assessment activities. NERC therefore

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[110] *See, e.g.,* WECC System Review Subcommittee, *2025 Data Preparation Manual for Interconnection-wide Cases*, https://www.wecc.org/wecc-document/13661; ERCOT Dynamics Working Group, *Dynamics Working Group Procedure Manual* (revision 24), https://www.ercot.com/committees/ros/dwg; ERCOT Steady State Working Group, *Steady State Working Group Procedure Manual* (Sep. 11, 2025), https://www.ercot.com/committees/ros/sswg; *and* ERAG Multiregional Modeling Working Group (MMWG), *Procedure Manual* (version 41), https://www.rfirst.org/wp content/uploads/2025/08/MMWG_Procedural_Manual_v41.pdf.

submits that this framework, to the extent it relies upon ERO-designated entities rather than an entity represented on the NERC Compliance Registry, represents an equally effective and efficient approach to addressing the reliability concerns underlying the Commission's paragraph 161 directive and helps to assure accurate Interconnection-wide models for system planning studies.

VII. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARDS IRO-010-6 AND TOP-003-8

Proposed Reliability Standards IRO-010-6 and TOP-003-8 reflect revisions to establish the uniform framework for the development of planning and operations models and ensure that IBR-specific data and parameters are addressed in Reliability Coordinator, Balancing Authority, and Transmission Operator data specifications.

As explained in Exhibit H, 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 31, 2025.

This section provides a summary of the revisions, which are identical in proposed Reliability Standards IRO-010-6 and TOP-003-8. The revisions are shown in redline in Exhibits A-2 and A-3. Additional information may be found in the Technical Rationale, included as Exhibit E to this petition, the Complete Record of Development, included as Exhibit H, and the Consideration of Order No. 901 Directives, included as Exhibit D.

A. Overview of Proposed Standards

The title of Reliability Standard IRO-010-6 is Reliability Coordinator Data and Information Specification and Collection. The purpose of the proposed standard remains unchanged: to prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and

assess the operation of its Reliability Coordinator Area. The standard remains applicable to the Reliability Coordinator, Balancing Authority, Generator Owner (to include newly-registered Generator Owners under the expanded NERC Registry criteria), Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider.

The title of Reliability Standard TOP-003-8 is Transmission Operator and Balancing Authority Data and Information Specification and Collection. The purpose of the proposed standard remains unchanged: To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area. The standard remains applicable to the Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider.

B. Revisions to Address IBR-Specific Data and Parameters

In addressing the relevant directives from Order No. 901, the Project 2022-22 drafting team reviewed the currently effective versions of the IRO-010 and TOP-003 standards and concluded that both standards had broad requirements that would allow the Reliability Coordinator, Transmission Operator, or Balancing Authority to request data and information needed to support their respective operations planning, analysis, or Real-time activities from generation and storage resources, including IBR.

To avoid ambiguity and ensure Order No. 901 directives are addressed, however, proposed Reliability Standards IRO-010-6 and TOP-003-8 would add "Inverter-based Resource (IBR)-specific data and parameters" to the list of information the Reliability Coordinator, Transmission Operator, and Balancing Authority must address in its documented data specifications. To demonstrate, proposed Reliability Standard IRO-010-6 Requirement R1 Part 1.1 would revise the currently effective requirement as follows:

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to:

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, as deemed necessary by the Reliability Coordinator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification ~~as deemed necessary by the Reliability Coordinator~~.

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As demonstrated in Exhibit A-3, NERC proposes these revisions in Reliability Standard TOP-003-8 Requirement R1 Part 1.1 and Requirement R2 Part 2.1.

These revisions would address the Order No. 901 directives related to the sharing of IBR data with Reliability Coordinators, Transmission Operators, and Balancing Authorities, including the Commission directive in paragraph 76,[111] as well as directives addressing IBRs in operations models, including those in Order No. 901 paragraphs 122 and 161.[112] The phrase "IBR-specific data and parameters" is intended to reflect what the Commission describes in the order as "IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions." The relocation of the phrase "as deemed necessary by the Reliability Coordinator" is intended to provide for clarity in the requirement.

[111] *See* Order No. 901 at P 76 ("Pursuant to section 215(d)(5) of the FPA, we…direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information, and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their…reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System.")

[112] *See* Order No. 901 at P 122 ("Pursuant to section 215(d)(5) of the FPA, we…direct NERC to develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, *operations*, and interconnection-wide models." (emphasis added); *see also id.* at P 161 (directing NERC to develop standards that require Reliability Coordinators, Transmission Operators, and Balancing Authorities to establish "necessary data exchange requirements" for such models).

C. Revisions to Establish the Uniform Framework for Modeling

To address Commission directives regarding the usage of a uniform framework in the development of planning and operations models, proposed Reliability Standards IRO-010-6 and TOP-003-8 would add a new requirement part specifying that requirements for model submissions are to be consistent with the model submitted for planning purposes, as applicable. To demonstrate, proposed Reliability Standard IRO-010-6 Requirement R1 Part 1.5 would revise the currently effective requirement as follows:

> R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to:
>
> ***
>
> 1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to~~.~~:
>
> 1.5.1 Specific deadlines or periodicity in which data and information is to be provided;
>
> 1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;
>
> 1.5.3 Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;
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> ~~1.5.3~~1.5.4 Provisions to update or correct data and information, as applicable or necessary~~.~~;
>
> ~~1.5.4~~1.5.5 A mutually agreeable format~~.~~; and
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> ~~1.5.5~~1.5.6 A mutually agreeable method(s) for securely transferring data and information.

As demonstrated in Exhibit A-3, NERC also proposes these revisions in Reliability Standard TOP-003-8 Requirement R1 Part 1.5.3 and Requirement R2 Part 2.5.3.

These modifications were made in response to Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Such directives include

those in Order No. 901 paragraphs 78, 104, 124, 125, 141, and 161. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that any operations model submissions be consistent with planning model submissions would ensure that they also reflect the uniform framework as directed by the Commission in Order No. 901.

Models submitted for planning purposes are typically made in accordance with the MOD-032 standard, though additional standards or regional requirements may apply. Some modifications to these planning models may be necessary to reflect considerations for operations. For example, simulation time constraints in an online operations environment may warrant a reduced model structure complexity. Such models may differ from, but should still be consistent with, more complex modeling that is submitted under MOD-032. As another example, consistent models would not be appropriate if an update was made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon as well as to reflect that entities may determine when such models are needed for their operations planning and Real-time functions.

D. Consideration of Additional Order No. 901 Directives

In addition to the Order No. 901 directives identified above, the Project 2022-02 drafting team considered the Commission's directive in paragraph 86 of Order No. 901 to consider "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."[113] The drafting team determined that the TOP-003 and IRO-010 Reliability Standards are already structured in an such a way that Reliability Coordinators, Balancing Authorities, and

[113] *Id.* at P 86.

Transmission Operators may request any type of data needed to support their operations planning, analysis, or Real-time functions. The drafting team considered that the transmission of information from the plant level is often addressed in interconnection agreements. The drafting team also considered that, under approved Reliability Standard PRC-028-1, each registered IBR will be required to have disturbance monitoring devices installed. Reliability Standard PRC-028-1 would require the Generator Owner to provide the data to a Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC within 15 calendar days of a request. Following consideration of these factors, the standard drafting team concluded that the appropriate entities have the authority to gather the data deemed necessary for reliability without the need to impose an additional, uniform burden on all generating facilities.

VIII. ENFORCEABILITY OF THE PROPOSED RELIABILITY STANDARDS

The proposed Reliability Standards 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.[114] 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 G provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

NERC has included a Potential Noncompliance (PNC) abeyance period for proposed Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the estimation of

[114] Order No. 672 at P 327.

aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. During the standard development process, multiple commenters expressed concern about their ability to obtain or estimate data for IBRs or DERs that were owned by entities not registered for compliance with NERC as the Commission directed in Order No. 901. While the proposed standard provides flexibility to entities on how they would estimate such data when unable to gather it directly, NERC recognizes that some concern remains about how such data gathering or estimation activities will be reviewed during compliance monitoring activities. To address this concern, NERC has included a two-year Potential Noncompliance (PNC) abeyance period in Section C. Compliance of proposed Reliability Standard MOD-032-2 that would provide as follows:

> **Potential Noncompliance (PNC) Abeyance Period**: For a period of two years following the phased-in compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. "Good faith" in this context refers to a sincere intention to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. For example, the CEA may not pursue compliance enforcement actions during this period for entities who submit estimated data and include the supporting data explanation and methods used as detailed in Requirement R2 Part 2.1 in a timely manner. The CEA may pursue actions against entities who do not submit data with supporting explanation and methods in a timely manner. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential

> noncompliance abeyance period and submit documentation as requested.

In NERC's November 8, 2024 supplemental filing to the Five-Year Performance Assessment required under 18 C.F.R. § 39.3(c), NERC described how it would begin using a "potential noncompliance abeyance period" to enhance NERC's standard development process agility, thereby reducing concerns over compliance risk during standards development so that the focus can be on addressing risks to reliability.[115] As NERC explained in that filing, this compliance abeyance period would encourage entities to share observations and experiences through implementation of new standards without fear of potential noncompliance (so long as they are acting in good faith) to mitigate reliability risks. This feedback loop, coupled with insights generated from more robust data collection from enforcement activities of trends, themes, and recommendations, would collectively be used to inform the standards development process after initial compliance of new standards to revise the standards prior to full enforcement.

The proposed estimation provisions in proposed Reliability Standard MOD-032-2 Requirement R1 Part 2.1 are novel requirements intended to improve how resources owned by non-registered entities are reflected in system studies in the absence of an enforceable requirement for the owner entities to provide it directly. As the Commission recognized in Order No. 901, estimated modeling data and parameters are approximations of actual modeling data and parameters, and there is some degree of error in estimated information.[116] However, the Commission also recognized that having estimated data would be an improvement upon having

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115 *Supplemental Filing of NERC to the Five-Year ERO Performance Assessment Report*, Docket No. RR24-4-000 at 3, 10 (Nov. 8, 2024). The Commission accepted NERC's five year performance assessment filings on December 19, 2024. *N. Am. Elec. Reliability Corp*., 189 FERC ¶ 61,211 (2024).

116 Order No. 901 at P 104.

no data at all.[117] Given concerns raised about such estimations, a Potential Noncompliance Abeyance Period could provide two important benefits for reliability.

First, by temporarily removing concerns about compliance implications, a Potential Noncompliance Abeyance Period would encourage entities with concerns about their data gathering or estimation efforts to seek guidance from the ERO Enterprise. To the extent this guidance results in a better estimation, it would result in better system models and thus better system studies more quickly than if the issue had been discussed during compliance monitoring activities in future years.

Second, a Potential Noncompliance Abeyance Period would provide a focused means for the ERO Enterprise to gather information and feedback on this aspect of the proposed standard. This information and feedback could inform the development of guidance or lessons learned on estimation methods or future revisions to the standard. This information and feedback could also inform the development of future changes to NERC's registration criteria, if such changes are ultimately needed to ensure the provision of adequate modeling data and parameters from "unregistered IBRs" and IBR-DERs as the Commission indicated in Order No. 901.[118]

In determining the appropriate length of time for the Potential Noncompliance Abeyance Period, NERC considered the urgency in the need to fully implement proposed Reliability Standard MOD-032-2 and the time that may be needed for information collection and analysis. NERC also considered the Commission's expectation that the need for estimating data (in lieu of

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117 *Id.*

118 *See id.* at P 109 ("We encourage NERC to continue its efforts to review and evaluate whether reliability gaps continue to remain and if new or modified functional registration categories or Reliability Standards are necessary to ensure the reliable operation of the Bulk-Power System. NERC may choose to revise, or the Commission may direct further revisions to, registration or Reliability Standards to ensure the provision of adequate modeling data and parameters from unregistered IBRs and/or IBR-DERs in the aggregate.")

having actual data) will decrease over time.[119] Based on these considerations, NERC determined that a two-year abeyance period, measured from the phased-in compliance date of Requirement R2 under the proposed implementation plan, would be appropriate.

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 the proposed definition of Distributed Energy Resource (DER) would become effective on the first day of the first calendar quarter after the effective date of the Commission's order approving proposed Reliability Standard MOD-032-2. The proposed Reliability Standard MOD-032-2 would become effective on the first day of the first calendar quarter that is 24 months after the effective date of the Commission's order approving the proposed Reliability Standard.

During this implementation period, Planning Coordinators/Transmission Planners would develop revised data requirements and reporting procedures addressing each of the new and revised IBR and DER items in Requirement R1 and Attachment 1. Entities would not be required to comply with Requirements R2, R3, and R4 relating to these revised Planning Coordinator/Transmission Planner data requirements and reporting procedures until 12 months after the effective date of Reliability Standard MOD-032-2.

To ensure that there are no gaps in data reporting during the phased-in compliance period, entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under

[119] *Id.* at P 107 (discussing revisions to the NERC registration framework, *pro forma* Large Generator Interconnection Procedures and Small Generator Interconnection Procedures, and revised transmission provider interconnection agreements as reducing the need for estimated data over time).

MOD-032-1 Requirement R1 and Attachment 1 unless they are able to comply with the revised Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under Reliability Standard MOD-032-2 Requirement R1.

Proposed Reliability Standards IRO-010-6 and TOP-003-8 would become effective on the first day of the first calendar quarter that is 36 months after the effective date of the Commission's order approving the proposed Reliability Standards.

Reliability Standards MOD-032-1, IRO-010-5, and TOP-003-7 would each be retired immediately prior to the effective date of the revised successor standard.

The proposed implementation plan 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." [120] In developing the proposed implementation timeframe, the drafting team considered the Commission's guidance in Order No. 901 to have all IBR standards developed in response to the Commission's directives in Order No. 901 to be implemented prior to 2030.[121] The drafting team also considered the time that would be necessary to update modeling data requirements and reporting procedures under proposed Reliability Standard MOD-032-2, including identifying the proper reporting entity for modeling data related to IBRs (including "unregistered IBRs" and aggregate DERs). Further, the drafting team considered that the MOD-032 standard would become applicable to the Distribution Provider for the first time.

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120 *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.")

121 Order No. 901 at P 226.

During the 24 months prior to the effective date of Requirement R1, applicable entities would be expected to participate in Planning Coordinator/Transmission Planner processes to change the modeling data reporting requirements related to IBRs and aggregate DERs and should be able to start working on data collection processes and methods. The applicable entities in Requirement R2 would then have an additional 12 months to complete and implement data collection prior to the compliance dates of Requirements R2, R3, and R4. This timeline would also allow for the development of new data estimation processes developed under proposed Reliability standard MOD-032-2 Requirement R2 Part 2.1 and for the development of technical rationale to support the use of models included on the Unacceptable Model List maintained by the ERO, where applicable.

The revised requirements in Reliability Standards IRO-010-6 and TOP-003-8 may not be practical to implement prior to full implementation of proposed Reliability Standard MOD-032-2; therefore, these standards were set to the same implementation timeline.

For the reasons stated above, the proposed implementation plan balances the urgency in the need to implement the Reliability Standards identified in Order No. 901 against the time needed to develop the necessary procedures or relevant capability. 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.

X. CONCLUSION

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

- proposed Reliability Standards MOD-032-2, IRO-010-6, TOP-003-8, the proposed definition of Distributed Energy Resource, 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 Standards MOD-032-1, IRO-010-5, and TOP-003-7, effective as proposed herein.

Respectfully submitted,

/s/ Lauren A. Perotti

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Date: November 4, 2025

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Exhibit A

Proposed Reliability Standards

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Exhibit A-1

Proposed Reliability Standard MOD-032-2
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

MOD-032-2 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
(The above was Posted under IRPTF SAR pre–Order No. 901)	
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

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):

Distributed Energy Resource (DER): A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** Data for Power System Modeling and Analysis

2. **Number:** MOD-032-2

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Generator Owner

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation;

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data that is responsive to the technical concern.

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

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

   - Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. **Compliance Monitoring and Enforcement Program:** Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

3. **Potential Noncompliance (PNC) Abeyance Period:**
Potential Noncompliance (PNC) Abeyance Period: For a period of two years following the phased-in compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. "Good faith" in this context refers to a sincere intention to

comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. For example, the CEA may not pursue compliance enforcement actions during this period for entities who submit estimated data and include the supporting data explanation and methods used as detailed in Requirement R2 Part 2.1 in a timely manner. The CEA may pursue actions against entities who do not submit data with supporting explanation and methods in a timely manner. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.
R2.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not

	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

	Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission

	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data

	in the format specified by the ERO or its designee.	the format specified by the ERO or its designee.	required data in the format specified by the ERO or its designee.	in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List

MOD-032-2 – ATTACHMENT 1
Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in Interconnection-wide cases. The joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify entity responsibility and data flow processes. The typical functional entity[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be identified by the bus number, name, and/or identifier that is assigned in conjunction with the Planning Coordinator, Transmission Owner, or Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
1. Each bus [TO] a. Nominal voltage b. Area, zone and owner 2. Aggregate Demand[3] [DP] a. Real and reactive power* b. In-service status* 3. Generating and storage units[4] [GO, TO[5], RP (for future planned resources only)] a. Real power capabilities - gross maximum and minimum values b. Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. Regulated bus* and voltage set point* (as typically provided by the TOP) e. Machine MVA base	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[3] [DP] 6. Wind plant model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control 8. Static Var Systems and FACTS [GO, TO, DP] 9. DC System Models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive sequence data b. Negative sequence data c. Zero sequence data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
f. Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. Generator type (hydro, wind, fossil, solar, nuclear, etc.) h. In-service status* 4. AC Transmission Line or Circuit [TO] a. Impedance parameters (positive sequence) b. Susceptance (line charging) c. Ratings (normal and emergency)* d. In-service status* 5. DC Transmission Systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. Nominal voltages of windings b. Impedance(s) c. Tap ratios (voltage or phase angle)* d. Minimum and maximum tap position limits e. Number of tap positions (for both the ULTC and NLTC) f. Regulated bus (for voltage regulating transformers)* g. Ratings (normal and emergency)* h. In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. Admittances (MVars) of each capacitor and reactor b. Regulated voltage band limits* (if mode of operation not fixed) c. Mode of operation (fixed, discrete, continuous, etc.) d. Regulated bus* (if mode of operation not fixed) e. In-service status* 8. Static Var Systems [TO] a. Reactive limits b. Voltage set point* c. Fixed/switched shunt, if applicable d. In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1)	a. parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
b. Real power capability c. DER type (solar, battery, diesel generator, etc.) 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. (Note: This may be impacted by an aggregation threshold for DER specified under footnote 7.) A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider’s system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner’s system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This Supporting Document describes the process by which changes may be made to the Unacceptable Models List. This process may only be revised through the NERC Standards Development Process.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
    a. The model name;
    b. Alternative model name(s), if any;
    c. Organization(s) the submitting entity represents;
    d. Description of the model's stated intent;
    e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
    f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
    g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
    h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.
5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving

the change request, the NERC RSTC shall also recommend an effective date for the change.

6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

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Exhibit A-1

Proposed Reliability Standard MOD-032-2
Redline to Last Approved (MOD-032-1)

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

MOD-032-2 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
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Board adoption	October 14, 2025

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):

Distributed Energy Resource (DER): A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   ~~1.1.~~4.1. Functional Entities:

   ~~1.1.1~~4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   ~~1.1.2~~4.1.3 Generator Owner

   ~~**1.1.3** Load Serving Entity~~

   ~~1.1.4~~4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.~~

   ~~1.1.5~~4.1.5 Resource Planner

   ~~1.1.6~~4.1.6 Transmission Owner

   ~~1.1.7~~4.1.7 Transmission Planner

   ~~1.1.8~~4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

   ~~MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is~~

approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation;

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each ~~registered~~functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~2.1.~~3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data~~;~~, that is responsive to the technical concern.

~~3.1.~~3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each ~~registered~~functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

The applicable entity shall keep data or evidence to show compliance ~~with~~ 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.

- Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. Compliance Monitoring and ~~Assessment Processes~~ Enforcement Program:
Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for ~~a list of~~performing compliance monitoring and ~~assessment processes~~enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

~~**1.3. Additional Compliance Information**~~

~~None~~

3. Potential Noncompliance (PNC) Abeyance Period:
For a period of two years following the phased-in compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2, Part 2.1 with respect to the provision of estimated aggregate DER data or

estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. “Good faith” in this context refers to a sincere intention to comply with Reliability Standard MOD-032-2 ~~regarding the provision of aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes in accordance with the data requirements and reporting procedures for the Planning Coordinator’s planning area developed under Requirement R1, subject to the estimation requirements of~~ Requirement R2, Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. For example, the CEA may not pursue compliance enforcement actions during this period for entities who submit estimated data and include the supporting data explanation and methods used as detailed in Requirement R2 Part 2.1 in a timely manner. The CEA may pursue actions against entities who do not submit data with supporting explanation and methods in a timely manner. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

~~Table of Compliance Elements~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R2.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;

	the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, ~~Load Serving Entity,~~ Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its

				Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

	within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

- ~~None.~~Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List

MOD-032-2 – ATTACHMENT 1~~:~~

Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in ~~*the*~~ Interconnection-wide cases. ~~*A*~~The joint Planning Coordinator ~~*may*~~/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify ~~*additional information that includes specific information required for each item in the table below. Each*~~entity responsibility and data flow processes. The typical functional *entity*~~[1]~~[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be ~~*as*~~ identified by the bus number, name, and/or identifier that is assigned in conjunction with the ~~*PC, TO*~~Planning Coordinator, Transmission Owner, or ~~*TP.*~~ Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	**short circuit**
1. Each bus [TO] a. ~~n~~Nominal voltage b. ~~a~~Area, zone and owner 2. Aggregate Demand~~[3]~~[2] [~~LSE~~DP] a. ~~r~~Real and reactive power* b. ~~i~~In-service status*	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System ~~S~~stabilizer [GO, RP(for future planned resources only)]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO]

~~[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).~~

~~[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
3. Generating and storage Units[4] ~~3~~ [GO, TO[5], RP (for future planned resources only)] a. ~~r~~Real power capabilities - gross maximum and minimum values b. ~~r~~Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. ~~s~~Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. ~~r~~Regulated bus* and voltage set point* (as typically provided by the TOP) e. ~~m~~Machine MVA base f. ~~g~~Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. ~~g~~Generator type (hydro, wind, fossil, solar, nuclear, etc) h. ~~i~~In-service status* 4. AC Transmission Line or Circuit [TO] a. ~~i~~Impedance parameters (positive sequence) b. ~~s~~Susceptance (line charging) c. ~~r~~Ratings (normal and emergency)* d. ~~i~~In-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. ~~n~~Nominal voltages of windings	5. Aggregated Demand[3] [~~LSE~~DP] 6. Wind ~~T~~turbine ~~Data~~model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]]~~Photovoltaic systems [GO]~~ ~~7.~~a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control. 8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC ~~s~~System models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

~~[3] Including synchronous condensers and pumped storage.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
b. ~~i~~Impedance(s) c. ~~t~~Tap ratios (voltage or phase angle)* d. ~~m~~Minimum and maximum tap position limits e. ~~n~~Number of tap positions (for both the ULTC and NLTC) f. ~~r~~Regulated bus (for voltage regulating transformers)* g. ~~r~~Ratings (normal and emergency)* h. ~~i~~In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. ~~a~~Admittances (MVars) of each capacitor and reactor b. ~~r~~Regulated voltage band limits* (if mode of operation not fixed) c. ~~m~~Mode of operation (fixed, discrete, continuous, etc.) d. ~~r~~Regulated bus* (if mode of operation not fixed) e. ~~i~~In-service status* 8. Static Var Systems [TO] a. ~~r~~Reactive limits b. ~~v~~Voltage set point* c. ~~f~~Fixed/switched shunt, if applicable d. ~~i~~In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.)		

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]		

~~Guidelines and Technical Basis~~

~~For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.~~

~~The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.~~

~~An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.~~

~~The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and~~

~~to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).~~

~~The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).~~

~~Rationale:~~

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

~~Rationale for R1:~~

~~This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short-circuit data also required to perform short-circuit studies. The addition of short-circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.~~

~~In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.~~

~~This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.~~

~~This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:~~

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.
4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

~~This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.~~

~~Rationale for R4:~~

~~This requirement will replace MOD-014 and MOD-015.~~

~~This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.~~

~~The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).~~

~~This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).~~

~~For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.~~

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. (Note: This may be impacted by an aggregation threshold for DER specified under footnote 7.) A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs, and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This Supporting Document describes the process by which changes may be made to the Unacceptable Models List. This process may only be revised through the NERC Standards Development Process.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
   a. The model name;
   b. Alternative model name(s), if any;
   c. Organization(s) the submitting entity represents;
   d. Description of the model's stated intent;
   e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
   f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
   g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
   h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.

5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving the change request, the NERC RSTC shall also recommend an effective date for the change.
6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

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Exhibit A-2

Proposed Reliability Standard IRO-010-6
Clean

Standard Development Timeline

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

Description of Current Draft

IRO-010-6 is posted for a 5-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
25-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection
2. **Number:** IRO-010-6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Transmission Operator
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments, as deemed necessary by the Reliability Coordinator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2 and Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R1	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	
6	TBD	Adopted by NERC Board of Trustees	FERC Order 901 Modifications

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Exhibit A-2

Proposed Reliability Standard IRO-010-6
Redline to Last Approved (IRO-010-5)

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

IRO-010-6 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection

2. **Number:** IRO-010-~~5~~6

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.

4. **Applicability:**

   4.1. Reliability Coordinator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Transmission Operator

   4.6. Transmission Owner

   4.7. Distribution Provider

5. **Effective Date:** See Implementation Plan for Project ~~2021-06.~~2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments, as deemed necessary by the Reliability Coordinator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification ~~as deemed necessary by the Reliability Coordinator~~.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to ~~.~~:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

~~**1.5.3**~~**1.5.4** Provisions to update or correct data and information, as applicable or necessary ~~.~~;

~~1.5.4~~1.5.5 A mutually agreeable format~~.~~; and

~~1.5.5~~1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or ~~e-mail~~email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, ~~Reliability Coordinator,~~ Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

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 the ~~mandatory and enforceable~~NERC 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~~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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2~~,~~ and Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
~~As defined in the NERC Rules of Procedure,~~ "Compliance Monitoring and Enforcement Program" ~~refers~~or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the ~~identification~~NERC Rules of Procedure) or the Commission-approved program of ~~the processes~~a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that ~~will be used to evaluate data or~~

~~information~~is responsible for ~~the purpose of assessing performance or outcomes~~performing compliance monitoring and enforcement activities with ~~the associated reliability standard~~respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R1.	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the ~~SDT~~DT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specification.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

- Project 2022-02 Implementation Plan
- Project 2022-002 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO- 010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	

6	TBD	Adopted by NERC Board of Trustees	FERC Order 901 Modifications

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-3

Proposed Reliability Standard TOP-003-8
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

TOP-003-8 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, as deemed necessary by the Transmission Operator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, but is not limited to:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

1.5.4. Provisions to update or correct data and information, as applicable or

necessary;

1.5.5. A mutually agreeable format;

1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, as deemed necessary by the Balancing Authority, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes, but is not limited to:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

2.5.4. Provisions to update or correct data and information, as applicable or necessary.

2.5.5. A mutually agreeable format.

2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator

Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (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 Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1, Part1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, Board Of Trustees approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5. Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1. Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7. Docket	

		No.RD25-5-000	
8	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-3

Proposed Reliability Standard TOP-003-8
Redline to Last Approved (TOP-003-7)

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

TOP-003-8 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-~~7~~8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-~~03~~02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, as deemed necessary by the Transmission Operator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification ~~as deemed necessary by the Transmission Operator~~.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following~~.~~:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

~~1.5.3.~~**1.5.4.** Provisions to update or correct data and information, as applicable

or necessary;

~~1.5.4.~~1.5.5. A mutually agreeable format;

~~1.5.5.~~1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, as deemed necessary by the Balancing Authority, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, ~~as deemed necessary by the Balancing Authority,~~ and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following~~.~~:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

~~**2.5.3.**~~**2.5.4.** Provisions to update or correct data and information, as applicable or necessary.

~~**2.5.4.**~~**2.5.5.** A mutually agreeable format.

~~**2.5.5.**~~**2.5.6.** A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or ~~e-mail~~email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or ~~e-mail~~email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in

Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence

for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the ~~Standard~~ Drafting Team (~~SDT~~DT) is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7 Docket No.RD25-5-000	

~~7~~8	TBD	~~Energy Assurance Modifications — Addition of Near-Term ERA.~~Adopted by the NERC Board of Trustees	~~Revised~~Revisions to address FERC Order No. 901 directives

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Exhibit B

Implementation Plan

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Implementation Plan

Project 2022-02 Uniform Modeling Framework for IBR

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-6 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-8 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-5 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard(s)

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

- None

Applicable Entities

- See subject standards

Glossary of Terms used in NERC Reliability Standards

This section includes a newly defined term used in the NERC Reliability Standards. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, the defined term will be removed from the individual standard and added to the NERC Glossary.

Proposed New Definition:

Distributed Energy Resource (DER):

A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

Background

As the penetration of DERs continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk-Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BPS. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DERs for planning studies (including both utility-scale and retail-scale DERs) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DERs.

Further, in Order No. 901,[1] the U.S. Federal Energy Regulatory Commission ("FERC") found that it is imperative for NERC to develop new or modified Reliability Standards to address reliability concerns "related to IBRs at all stages of interconnection, planning, and operations."[2]. Among other things, FERC directed NERC to develop requirements addressing the provision of IBR and DER data to the entities responsible for the planning and operation of the BPS. Detailed information on the specific FERC Order No. 901 directives addressed through this project is available in Project 2022-02 Consideration of Order No. 901 Directives.

Proposed Reliability Standard MOD-032-2 replaces Load-Serving Entity with Distribution Provider as an applicable entity. Data items specific to IBRs and DERs were added to Attachment 1: Data Reporting Requirements, consistent with addressing the FERC Order No. 901 directives. Proposed Reliability Standard MOD-032-2 also adds a new Part 1.4 in Requirement R1, which would require the Planning Coordinator and Transmission Planner to specify submission of standard library dynamic models, user-defined models or both. Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. New Requirement R1, Part 1.4.2 is responsive to FERC concerns about model usability and non-convergence by requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions. New Requirement R2, Part 2.1 addresses estimation of unregistered IBR or DER data where actual data is not available, consistent with the directives in Order No. 901. New Requirement R2, Part 2.2 addresses the provision of dynamic models accepted under the MOD-026 standard, and new Requirement R2, Part 2.3 requires any entity submitting a model included on the Unacceptable Model List maintained by the ERO to include a technical rationale with its submission supporting the use of the model. Altogether, these modifications establish a uniform modeling framework that incorporates both IBR and DER data and facilitates model accuracy in alignment with FERC Order No. 901.

[1] Reliability Standards to Address Inverter-Based Resources, Order No. 901, 185 FERC ¶ 61,042 (2023).
[2] Id. at P 25

Revisions in the Reliability Standards TOP-003-8 and IRO-010-6 data specification standards specify that entities responsible for developing and distributing data specifications shall include requirements for model submissions consistent with the model submitted for planning purposes, as applicable.

General Considerations

In developing this implementation plan, the drafting team (DT) considered the time that would be necessary to update modeling data requirements and reporting procedures for MOD-032-2, including identifying the proper reporting entity for modeling data related to IBRs (including IBRs that are not DERs and do not meet the criteria that would require the owner(s) to register with NERC for mandatory Reliability Standards compliance purposes) and aggregate DERs. The DT also considered that the standard would become applicable to the Distribution Provider (DP) for the first time. During the 24 months prior to the effective date of Requirement R1, the applicable entities would be expected to participate in PC/TP processes to change the modeling data reporting requirements related to IBRs and aggregate DERs and should be able to start working on data collection processes and methods. The applicable entities in Requirement R2 would then have an additional 12 months to complete and implement data collection prior to the compliance dates of Requirements R2, R3, and R4. This timeline also allows for the development of new data estimation processes developed under MOD-032-2 Requirement R2, Part 2.1 and for the development of technical rationale to support the use of models included on the Unacceptable Model List maintained by the ERO, where applicable. Requirements adjusted in Reliability Standards IRO-010-6 and TOP-003-8 may not be practical to implement prior to full implementation of MOD-032-2, and therefore were set to the same implementation timeline. One additional limitation the DT considered is the requirement for all FERC Order No. 901 directives to be fully implemented by January 1, 2030, including those to be addressed by future standard revisions that may be dependent upon the implementation of these standard revisions.

In summary, this implementation plan would provide a full 36 months for MOD-032 Requirements R2, R3, R4, IRO-010, and TOP-003 from FERC approval until data is required to be reported under the revised requirements. During the phased-in compliance period for Requirements R2-R4, entities shall continue to provide data and perform other required actions in accordance with specifications developed under Reliability Standard MOD-032-1, unless entities are able to comply with the revised requirements sooner.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource is provided below. Where the DT 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 MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator and Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

During the phased-in compliance period, entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 unless they are compliant with revised Planning Coordinator/Transmission Planner data requirements and reporting procedures under Reliability Standard MOD-032-2 Requirement R1.

Definition – Distributed Energy Resource (DER)

Where approval by an applicable governmental authority is required, the definition of Distributed Energy Resource (DER) shall become effective on the first day of the first calendar quarter that is after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard IRO-010-6

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard TOP-003-8

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1

Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard IRO-010-5

Reliability Standard IRO-010-5 shall be retired immediately prior to the effective date of Reliability Standard IRO-010-6 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard TOP-003-7

Reliability Standard TOP-003-7 shall be retired immediately prior to the effective date of Reliability Standard TOP-003-8 in the particular jurisdiction in which the revised standard is becoming effective.

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Exhibit C

Order No. 672 Criteria

EXHBIIT C

Order No. 672 Criteria

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

Models provide the foundation of virtually all power system studies used to assess the reliability of the Bulk-Power System. Power system studies rely on models to predict system performance under various conditions. It is therefore important that models, including all their data, are complete, accurate, and up to date. Over the last decade, the Bulk-Power System has undergone a remarkable transformation. The resource mix, once consisting generally of large, synchronous generators, is increasingly comprised of relatively smaller Inverter-Based Resources ("IBRs") and Distributed Energy Resources ("DERs"). Such resources have unique technical and

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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.").

operational characteristics which must be modeled accurately in system studies. NERC and the Commission, however, have identified deficiencies in how these resources are modeled, deficiencies which have implications for the system studies that rely on these models and the actions that are taken in response to these studies. Several Bulk-Power System events in recent years have demonstrated the risks to reliability that may result from unexpected IBR performance. Further, failing to understand the nature and extent of the IBRs and DERs connected to or affecting the Bulk-Power System can affect how entities plan for reliable operation of the Bulk-Power System.

To address these issues, and in satisfaction of several directives in Order No. 901,[3] NERC proposes Reliability Standards MOD-032-2, IRO-010-6, and TOP-003-8. Proposed Reliability Standards MOD-032-2, IRO-010-6, and TOP-003-8 would advance the reliability of the Bulk-Power System by establishing a uniform modeling framework to improve how IBRs are accounted for in system models and, ultimately, the system studies in the operations and planning horizons that rely on those models.

Proposed Reliability Standard MOD-032-2 – Data for Power System Modeling and Analysis would advance reliability and improve upon the currently effective MOD-032 standard through requirements intended to ensure that the entities responsible for planning the Bulk-Power System have the data and information they need to build system models that accurately reflect the performance of IBRs on their portions of the Bulk-Power System, as well as the performance of DERs that can impact Bulk-Power System reliability. Proposed Reliability Standard MOD-032-2 consists of four requirements, an Attachment 1 describing the information required to effectively model the interconnected transmission system in the transmission planning horizons, and a new

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

supporting document describing the ongoing process by which NERC will maintain a list of equipment models that structurally do not represent equipment to a suitable fidelity for use in building system models (called the "Unacceptable Models List").

Proposed Reliability Standards IRO-010-6 and TOP-003-8 reflect revisions to establish the uniform framework for the development of planning and operations models and ensure that IBR-specific data and parameters are addressed in Reliability Coordinator, Balancing Authority, and Transmission Operator data specifications. To avoid ambiguity and ensure Order No. 901 directives are addressed, proposed Reliability Standards IRO-010-6 and TOP-003-8 would add "Inverter-based Resource (IBR)-specific data and parameters" to the list of information the Reliability Coordinator, Transmission Operator, and Balancing Authority must address in its documented data specifications. To address Commission directives regarding the usage of a uniform framework in the development of planning and operations models, proposed Reliability Standards IRO-010-6 and TOP-003-8 would add a new requirement part specifying that requirements for model submissions are to be consistent with the model submitted for planning purposes, as applicable.

The proposed Reliability Standards address several Commission directives in Order No. 901 related to IBR data sharing and modeling, as well as several findings and recommendations from NERC reports and lessons learned on past Bulk-Power System events. As such, it provides an important foundation for completing the operation and planning studies contemplated in the next phase of standards development under NERC's Order No. 901 Work Plan. 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.[4]

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 MOD-032-2 would continue to apply to the Balancing Authority, Generator Owner, Planning Authority/Planning Coordinator, Resource Planner, Transmission Owner, Transmission Planner, and Transmission Service Provider, as in currently effective Reliability Standard MOD-032-1. Proposed Reliability Standard MOD-032-2 would replace the Load Serving Entity, an applicable functional entity identified in Reliability Standard MOD-032-1, with the Distribution Provider. The Load Serving Entity is a functional entity category that is no longer registered for mandatory standards compliance purposes. Following Commission approval of NERC's proposed revised *Glossary* definition of Generator Owner,[5] proposed Reliability Standard MOD-032-2 would apply to a broader category of Generator Owners than those subject to currently effective Reliability Standard MOD-032-1; specifically, the Generator Owners that own the non-Bulk Electric System IBRs that NERC will register in accordance with revisions to its Rules of Procedure approved by the Commission in 2024.

Proposed Reliability Standard IRO-010-6 would continue to apply to the Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator,

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[4] *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.").

[5] In August 2025, NERC submitted a petition seeking Commission approval of revised definitions of the terms Generator Owner and Generator Operator used in the NERC Glossary. As explained in NERC's petition, the revised definitions are intended to align the definitions of those terms used in NERC Reliability Standards with the revised registration criteria approved by the Commission in 2024. *See Petition of NERC for Approval of Revised Terms "Generator Owner" and "Generator Operator" used in NERC Reliability Standards and Request for Expedited Action*, Docket No. RD25-10-000 (Aug. 27, 2025).

Transmission Owner, and Distribution Provider. Proposed Reliability Standard TOP-003-8 would continue to apply to the Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider.

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.[6]

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 G**. 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 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.[7]

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

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[6] *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.").

[7] *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.").

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.[8]

The proposed Reliability Standards achieve their reliability goals effectively and efficiently in accordance with Order No. 672. Proposed Reliability Standard MOD-032-2 would provide robust and technically justified requirements for Planning Coordinator/Transmission Planner data specifications, including minimum requirements for IBR and DER-specific data and modeling parameters. While establishing robust minimum requirements, the proposed standard also provides sufficient flexibility to account for differences in regional planning areas. Proposed Reliability Standards IRO-010-6 and TOP-003-8 address consideration of IBR-specific data and parameters and provide for consistency in model submissions across planning and operations standards, where applicable.

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.[9]

The proposed Reliability Standards do not reflect a "lowest common denominator"

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[8] *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.").

[9] *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.").

approach. In accordance with the Commission's direction in Order No. 901, proposed Reliability Standard MOD-032-2 would improve system models and the planning studies that rely on those models by improving the process for collecting data and models that reflect the unique operational characteristics of IBR and DER resources. The proposed standard accounts for differences across planning areas and the rapid pace of technological change. Proposed Reliability Standards IRO-010-6 and TOP-003-8 would improve how operations and Real-time data specifications account for IBR resources and ensure for consistency in models submissions across the planning and operations standards.

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.[10]

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 and DERs may vary by region, proposed Reliability Standard MOD-032-2 would include minimum requirements that must be addressed in Planning Coordinator/Transmission Planner data specifications. The proposed standard would allow flexibility in identification of entities responsible for providing data, how planners account for the aggregate impact of DERs affecting reliability in their planning areas, and in the models submitted in satisfaction of Planning Coordinator/Transmission Planner data specifications. Proposed Reliability Standards IRO-010-6

[10] *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.").

and TOP-003-8 would apply consistently throughout North America while recognizing variations in the information that is required to perform Real-time and operations analysis in different areas.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[11]

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 proposed standards would require the same performance by each of the applicable entities.

9. The implementation time for the proposed Reliability Standard is reasonable.[12]

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 definition of Distributed Energy Resource (DER) would become effective on the first day of the first calendar quarter after the effective date of the Commission's order approving proposed Reliability Standard MOD-032-2. The proposed Reliability Standard MOD-032-2 would become effective on the first day of the first calendar quarter that is 24 months after the effective date of the Commission's order approving the proposed Reliability Standard.

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[11] *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.").

[12] *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.").

During this implementation period, Planning Coordinators/Transmission Planners would develop revised data requirements and reporting procedures addressing each of the new and revised IBR and DER items in Requirement R1 and Attachment 1. Entities would not be required to comply with Requirements R2, R3, and R4 relating to these revised Planning Coordinator/Transmission Planner data requirements and reporting procedures until 12 months after the effective date of Reliability Standard MOD-032-2.

Proposed Reliability Standards IRO-010-6 and TOP-003-8 would become effective on the first day of the first calendar quarter that is 36 months after the effective date of the Commission's order approving the proposed Reliability Standards. The revised requirements in Reliability Standards IRO-010-6 and TOP-003-8 may not be practical to implement prior to full implementation of proposed Reliability Standard MOD-032-2, and therefore were set to the same implementation timeline.

Reliability Standards MOD-032-1, IRO-010-5, and TOP-003-7 would each be retired immediately prior to the effective date of the revised successor standard.

The proposed implementation plan is attached as **Exhibit B** to this petition. As discussed more fully in Section IX of NERC's petition, the proposed implementation plan reflects a measured consideration of the factors influencing the reasonableness of the time provided for implementation, including the time that would be necessary to update modeling data requirements and reporting procedures under proposed Reliability Standard MOD-032-2, and time that would be needed to respond to those data requirements and reporting procedures. The drafting team considered the fact that the MOD-032 standard would become applicable to the Distribution Provider for the first time.

These factors are carefully balanced against the demonstrated reliability need to implement these requirements, which is reflected in the Commission's guidance in Order No. 901 to have all IBR standards developed in response to the Commission's directives in Order No. 901 to be implemented prior to 2030.[13]

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[14]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved processes for developing and approving Reliability Standards. **Exhibit H** 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.[15]

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

[13] Order No. 901 at P 226.

[14] *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.").

[15] *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.").

Reliability Standards conflict with other vital public interests.

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

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

[16] *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.").

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Exhibit D

Consideration of Order No. 901 Directives

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Consideration of FERC Order No. 901 Directives

Milestone 3: Project 2022-02 Uniform Modeling Framework for IBR
September 2025

On October 23, 2023, FERC issued a Final Rule, Order No. 901, directing the North American Electric Reliability Corporation (NERC) to develop new or modified Reliability Standards that address aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project has a FERC regulatory deadline of November 4, 2025. Below provides the directives from FERC Order 901 along with the drafting team's (DT's) consideration of the directives.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
P7. "… Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate…"	IRO-010 MOD-032 TOP-003	A timeline has been drafted to meet the regulatory deadline of November 4, 2025. Completed tasks listed below. • An industry workshop completed January 14-17, 2025. (outreach) • Many virtual DT meetings completed weekly from January – March 2025. (publicly posted) • In-person DT completed February 11-13, 2025. (publicly posted) • Industry Webinar March 6, 2025. (publicly posted) • DT outreach with trade groups and entities March 3-14, 2025 • Industry comment and ballot period April 17-May 16, 2025. (publicly posted)

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
		• A second industry workshop completed June 3-5, 2025. (publicly posted) • Many virtual meetings were completed weekly from May 19-July 23, 2025. • Industry outreach with trade groups and entities July 3-23, 2025. • Industry comment and ballot period August 8-September 10, 2025.
P76. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information, and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System. As several commenters indicate, ensuring the sharing of appropriate IBR modeling data is critical to create and maintain the models used in reliability studies, and in turn to ensure that Bulk-Power System transmission planners or operators are able to plan for, operate, and reliably integrate IBRs onto the Bulk-Power System."	IRO-010 MOD-032 TOP-003	**Theme:** Inverter-Based Resource (IBR) /Generator Owner to provide specific modeling data. IRO-010 and TOP-003: • While TOP-003 and IRO-010 allow any data to be requested, the DT felt it was important to add "IBR-specific data and parameters" specifically to IRO-010-6 Requirements R1, subpart 1.1 and TOP-003-8 Requirement R1, subpart 1.1 and Requirement R2, subpart 2.1 to ensure it is clear what data may be specifically requested to address FERC Order No. 901. In addition, IBR encompasses IBR-DER, and this information could be requested. • The DT considered adding a new subpart at the end of Requirement R1 (e.g., Part 1.6), but after reviewing requirement language, the DT determined the data and information lists within the existing subparts were the appropriate place to capture IBR-specific modeling data and parameters.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
		MOD-032: • Generator Owner and Generator Operator – The DT decided to maintain applicability for just the Generator Owner and did not add Generator Operator as a functional entity to the applicability section. If data is needed from the Generator Operator, then the Generator Owner can reach out to the Generator Operator for necessary data via contractual obligations, etc. The DT does not find it necessary to require two applicable entities when one oversees the other. • The DT modified Attachment 1 to include generation and storage units, removed photovoltaic system (covered within IBR) and added Inverter-Based Resources. The wind turbine was updated for clarity that it is for Type 1 and Type 2, which is not included in the IBR definition.
P77. "With regard to AEU and ACP/SEIA's comments that the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners and operators, we believe that this request may already be addressed through each transmission planner's existing processes. For example, the New York Independent System Operator (NYISO) and CAISO both have processes for obtaining such data after demonstrating a need for the specific information requested and that the required information protection and non-disclosure agreements are signed. Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's	MOD-032	**Theme:** Information going from Transmission Owner to Generator Owner/Generator Operator (consider): MOD-032 • There is no specific requirement within MOD-032 that requires Transmission Owners to share data with the Generator Owners and Generator Operators (and such a requirement would not be aligned with the purpose of MOD-032). However, Transmission Planners and Planning coordinators have a framework where requests for data can be sent for inclusion for the Interconnection-wide models. At this time, the DT does not see a need for a requirement to be drafted requiring Transmission Owners to provide data to Generator Owners and Generator Operators. The DT believes this is most appropriately addressed

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." **P74.** "AEU and ACP/SEIA ask that, in addition to data provision requirements for generator owners and operators, the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners. For example, AEU explains that generator owners and operators also require data from transmission owners to support accurate modeling and performance, e.g., short circuit data, grid data for offshore wind, information on other power electronic devices around the IBR plant, and voltage harmonics. AEU adds that putting requirements on transmission owners would be consistent with revisions being developed for NERC's Modeling, Data, and Analysis (MOD) Reliability Standards."		through processes that exist outside of the MOD-032 Reliability Standard and concurs with the suggestion in P77 that these processes are already in place.
P78. "Commenters raised general concerns that mandating specific modeling and data submissions would reduce the flexibility and discretion of transmission planners and operators to identify the information they need. We find that, given the need for IBRs to operate in a predictable and reliable manner to ensure the reliable operation of the Bulk-Power System, it is necessary to establish uniform, minimum categories or types of data that must be provided so that Bulk-Power System planners and operators can predict the behavior of all IBRs. As discussed in more	MOD-032 TOP-003 IRO-010	**Theme:** Individual use of approved IBR models. (Uniform modeling framework) **Applicability:** Transmission Planner and Transmission Operator • Modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establish an improved uniform modeling framework. IBR has been included in Attachment 1 of MOD-032 under steady state (item 3), dynamics (item 7), and short circuit specifying the minimum types of IBR data and capabilities that need to be collected as required per FERC Order No. 901.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions."		• Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.
P86. "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."**	TOP-003 IRO-010	**Theme:** Disturbance and monitoring (Consider) (real-time operations) **Applicability:** Generator Owner TOP-003/IRO-010 • TOP-003 and IRO-010 Reliability Standards are already structured in an open way so that any type of data needed can be requested at any time. In addition, transmission of information from the plant level is generally dealt with via interconnection agreements and does not rise to the level of a requirement being needed at this time. Lastly, PRC-028 PMU devices must be installed for every IBR installation. These additional monitoring devices will allow additional data requests related to those devices, if the applicable entities find that useful. Because of the two items above (the open method for data requests and the PRC-028 PMU devices), the standard balances the needs for the Transmission Operator to gather the data deemed necessary for reliability without uniform burden on all generating facilities.
P102. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal, with modification. Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1)	MOD-032 IRO-010 TOP-003	**Theme:** 1) Transmission Owner directed to provide data for unregistered IBR and 2) Distribution Provider directed to provide data for IBR-DER **Applicability:** Transmission Owner and Distribution Provider

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System."		• The DT focused on the MOD-032 standard to address this directive from FERC. The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the MOD-032 standard. In response to comments seeking more precision, the MOD-032 standard uses the phrase "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes" to refer to the IBR resources encompassed by the term "unregistered IBR" in Order No. 901. • While the DT agrees that the Transmission Owner would be the typical entity for providing unregistered IBR data and the Distribution Provider would be the typical entity to provide DER data (as noted in Attachment 1 of MOD-032), the DT modified the Requirement language in response to comments to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2. Determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System, requires engineering judgment and is not something that would be appropriate to precisely specify in a reliability standard. Thus, Attachment 1 footnote 7 was added to explicitly allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard), and to add references back to the MOD-032 standard. The DT determined that the IRO-010 and TOP-003 standards already included language in place to address IBR impacts.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
P104. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) Estimation, if not able to get data from unregistered IBRs, 2) an explanation of the limitations of the availability of data, 3) explanation of the limitations of any data provided by unregistered IBRs, and 4) method for estimation. (directive) **Theme 2:** Implement a process or mechanism by which Transmission Owners would receive modeling data and parameters. (consider) **Applicability:** TO • The DT added Requirement R2, Part 2.1 allowing the functional entity to use the method of estimation should it find itself in a place unable to gather unregistered IBR data or DER data. However, it must include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. • In addition, the DT added an explanation of the resources that are intended to be captured. In proposed MOD-032, "unregistered IBR" are described as IBRs that are not Distributed Energy Resources, as the DT proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as owning either category 1 or category 2 assets). As suggested by commenters, the DT has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application. • While previous drafts of the MOD-032 standard used the shorthand phrase "unregistered IBR" to establish consistency with FERC Order No. 901, with the more fulsome description of

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
the reliability of the Bulk-Power System. To support this data collection, we further direct **NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."**		those resources in the footnote, the DT moved this description to the requirement text (in lieu of the phrase "unregistered IBR") in response to comments. • It is important to note that Order No. 901 predated the changes NERC made to the Rules of Procedure to ensure that the owners and operators of such IBR resources would be registered with NERC for mandatory compliance purposes. NERC does not register IBRs as resources, but rather the owners of such resources based on the registry criteria for Generator Owner and Generator Operator. There are two categories of each: owners and operators of BES Facilities (category 1 GOs/GOPs); and owners and operators of 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 (category 2 GOs/GOPs). In Order No. 901 parlance, ownership or operation of IBR resources meeting these criteria would require owner/operator registration and therefore would be considered "registered IBRs". In Order No. 901 parlance, ownership or operation of IBR resources that do not meet these criteria but are connected to a transmission system (i.e., are not Distributed Energy Resources) would not require owner/operator registration and therefore would be considered "unregistered IBR." • The DT discussed implementing a process or mechanism by which Transmission Owners would receive modeling data and parameters in depth. It was determined that if a TO is unable to gather data for unregistered IBRs and DERs, it is better to not

FERC Order No. 901 Directives		
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		mandate a specific process for how Transmission Owners acquire or estimate data. Obtaining data for unregistered IBRs should not pose a significant challenge because such facilities are likely directly connected to a TO system and provision of necessary data should be specified in interconnection agreements or other contracts. Obtaining data for DERs would be more challenging as these facilities are connected to the TO system through a separate unregistered DP. In such cases, it is prudent to allow various estimation methods to be used. • The IRO-010 and TOP-003 Reliability Standards are drafted in a way that is open-ended and allows the respective applicable entities to request data needed. However, project 2022-02 DT added "Inverter-based Resource (IBR) specific data and parameters" to ensure it is clear that entities can request data when needed for operations assessments. To the extent modeling is needed, it should be consistent with modeling data provided under MOD-032 modeling framework. Therefore, the DT made changes to the IRO-010 and TOP-003 standards to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes under MOD-032, as applicable.
P105. "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. (Directive) **Theme 2:** Consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters. (Consider)

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modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."		**Applicability:** Distribution Provider The DT added a new Requirement R2, Part 2.1 that if the responsible entity is unable to gather unregistered IBR data (*see description above*) or DER data and provide it to the Transmission Planner and Planning Coordinator, as specified in the data requirements and reporting procedures developed under Requirement R1, the responsible entity shall provide an estimate of the modeling data and parameters and include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. The DT discussed the possible mechanism by which Distribution Providers would receive modeling data and parameters. The DT did not feel this rose to the level of a requirement as the Distribution Provider can ask for the modeling data and parameters from the respective entity.
P106. "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead	MOD-032 IRO-010 TOP-003	**Theme:** Who is the responsible entity when no registered DP of IBR-DER (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation. • After much deliberation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for collecting and providing data for DERs

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to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."		connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." • The DT asked industry the following question: "Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system?" Some commenters agreed that the TO is the correct entity who should gather data if there is no associated registered DP between the DER connection point and the TO system. However, many comments received stated that the TO has no authority to collect data, and the following entities would be better suited to gather the data needed: Registered DP, Balancing Authority, Planning Coordinator, LSE, Generator Owner, Transmission Operator, and Resource Planner. Based on this feedback, the DT modified the Requirement language to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2.
P108. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request	MOD-032 IRO-010 TOP-003	**Theme:** Minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers that are necessary to predict the behavior of all

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that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear. As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions. By contrast, we believe that a directive to task distribution providers as the appropriate registered entity to collect and share the modeling data and parameters of IBR-DERs in the aggregate is preferable to deferring to the stakeholder process as suggested by APS. The distribution provider, as the entity providing and operating the lines between the transmission and distribution systems, is the entity best situated to have access to the data necessary for accurate estimation and, other than Indicated Trade Associations that suggested the piecemeal approach already discussed above, no commenter identified other potential entities as an equally efficient option."		IBRs and to ensure that compliance obligations are clear (ERO Approved Acceptable Criteria for Models/IEEE1547 ref./modify req./Tech rationale) **Applicability:** Transmission Planners, Transmission Operators, Transmission Owners, and Distribution Providers • The DT added Requirement R1, Part 1.4 to specify dynamic model submission requirements in Planning Coordinator/Transmission Planner data requirements and reporting procedures. • The focus of Requirement R1 Part 1.4 is obtaining accurate and usable models for IBRs. New Requirement R2 Part 2.3 provides that models with known deficiencies, such that the ERO included them on the Unacceptable Model List, shall not be submitted without technical justification. • Attachment 1 was modified to categorize the types of data required as per the directive (IBR, aggregate DER, Storage) necessary to facilitate model development. • Requirement R2, Part 2.1 requires entities to estimate unregistered IBR and IBR-DER data if the entity responsible for providing such data is unable to gather it.
P122. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop	MOD-032 IRO-010	**Theme**: Require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-

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new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."	TOP-003	circuit, and dynamic conditions when developing planning, operations, and Interconnection-wide models. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the DT determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their Interconnection-wide models and subsequently their planning cases. The DT considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The DT further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

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		To bookend these criteria for acceptable models, proposed Requirement R2 would also require any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The Unacceptable Models List includes models that NERC has identified over time as having known issues. While the DT initially proposed to foreclose the use of such models, the DT considered feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The DT believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns. The DT debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the DT ultimately decided to include this requirement in Requirement R2 as it relates to how entities respond to data specifications. The DT has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or

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		remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the DT has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for entities for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff are currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.
P124. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and		**Theme:** Nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies. (Uniform Modeling framework)

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dynamics studies. We acknowledge NERC's comment that user-defined models may be helpful for specific local reliability studies; however, the user-defined model cannot be used in place of nation-wide approved component models for regional analysis or interconnection-wide analysis because the user-defined model may cause non-convergence and other issues. However, NERC may allow the submission of user-defined models alongside the approved industry generic IBR model. Various entities do not accept user-defined models or only accept them for limited instances along with the open-source code which then allows internal model components to be viewed and modified. For example, PJM does not accept user-defined models and requires generic models for model verification in accordance with currently effective Reliability Standards MOD-026-1 and MOD-027-1. NYISO accepts a user-defined model in limited instances but requires either the open-source code (allowing anyone to access the internal model) or dynamic link library data and code files (compiled code that must be decompiled to view the internal model) that must be supplied for existing power flow software and in perpetuity."		The uniform modeling framework established in the proposed MOD-032 will focus on the use and representation of positive sequence phasor domain (PSPD) models in registered entity footprints and in Interconnection-wide models. Interconnection-wide modeling may be different from the models used in specialized studies dedicated to a particular technical objective. The ERO Unacceptable Models List applies to the models where NERC Reliability Standards require its use (generally for planning and operation models where multiple entities share information beyond their portion of the electric system, which includes Interconnection-wide models). Further guidance for interconnection applications can be found in the *NERC Dynamic Model Recommendations*. The DT considered introducing an approved model list for use in building cases specifically for Interconnection-wide analysis through Requirement R1 Part R1.2 of the proposed MOD-032, however, pre-defining a limited set of models that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To meet this directive, the DT modified Requirement R1 of MOD-032 by specifying the use of standard library "generic" models in Interconnection-wide cases while allowing the use of user-defined models. This provision was careful to address typically reported issues associated with user-defined models (UDMs) including non-convergence, by requiring that TP/PCs establish usability requirements for UDMs while incorporating an open, transparent process of identifying deficient models through the use of the "MOD-032 Supporting Documentation – Process for Updating the Unacceptable Models List Maintained by the ERO" and the "ERO Unacceptable Model list". Any TPs/PCs accepting UDMs shall provide

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		their UDM requirements to other PCs/TPs within the Interconnection upon request. The DT believes this approach balances the practical limitations of "generic models" raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop with the need for an improved uniform modeling framework. The combination of specifying the use of standard library component models approved and offered by software simulation tools, along with the ERO maintained Unacceptable Model List and its processes, will ensure that models used in interconnection wide analysis are robust enough while accuracy is not compromised to any level of detail deemed necessary. The introductions to this framework increase the data specifications requirements when user-defined models are used. TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P125. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models. One example of a way NERC could meet this directive would be to require an equivalent generic library model along with all submissions of user-defined models so that the generic library model can be used when combining	MOD-032 IRO-010 TOP-003	**Theme:** Nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build Interconnection-wide models. (Uniform Modeling framework /Req language) • Nation-wide approved components via generic library models are addressed via the development of a framework established in the proposed MOD-032-2 through improvements to Requirements R1, R2, and R3. The inclusion of ERO Unacceptable Models List, MOD-032 Supporting Document, and additional

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neighboring transmission system models and in interconnection-wide models."		requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. • The PC and TP are allowed to require provision of generic models, but if equipment-specific models satisfy usability criteria, and processes established through Requirements R1, R2, and R3 of the proposed MOD-032 standard, they are not prohibited. The framework explicitly allows for the submission of equivalent generic library models along with submissions of user-defined models which allows for the use of generic library models when combining neighboring transmission system models and Interconnection-wide models. • TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P141. "We also direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior. Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to	MOD-032 IRO-010 TOP-003	**Applicability**: GO • Nation-wide approved components via generic library models are addressed via the modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establishing an improved uniform modeling framework. This approach is aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop. • MOD-032, Attachment 1 was modified to specifically add that capabilities related to momentary cessation, tripping, and Ride-

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create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives. Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior). Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on		through, be reflected in the required model data for IBR and DER. • Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.

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the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives. Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models. Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System."		
P146. Accordingly, **we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to**	MOD-032 IRO-010 TOP-003	**Theme**: IBR-DER Model • As per the directive, the DT is requiring the modeling of aggregate DER through requirement R1 and Attachment 1. The currently available DER_A model is sufficient only for positive sequence phasor domain simulations. With the variety of other simulation domains (such as EMT and short circuit) necessary to study IBRs, mandating this model could prevent TPs or PCs from

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be able to perform respective system studies. For example, the new or modified Reliability Standards could require models of IBR-DERs (i.e., DER_A model) to adequately reflect the steady-state and dynamic aggregate resource performance in both a transmission area and across the interconnection. Additionally, estimated modeling data and parameters of IBR-DERs that in the aggregate (i.e., DER_A model) have a material impact on the Bulk-Power System could be used where measured and collected data is not available. We believe requiring the DER_A model will address NERC's request for entities to work collaboratively with the state regulators to identify, implement, and perform an effective model validation approach for IBR-DERs in the aggregate as opposed to requiring validated models of IBR-DER in the aggregate that can have a material impact on the reliable operation of the Bulk-Power System.		performing their studies. This further reinforces the DT's election to not require the use of the DER_A model, but rather a model that achieves specific performance criteria and conforms with MOD-032 edits in Attachment 1 and Requirement R1. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, not Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection (rather than mandating use of a defined set of models). Specific fidelity/accuracy evaluations are beyond the scope of MOD-032. • The DT considered referencing the DER_A model specifically, but refrained due to the rapidly evolving nature of models and concerns for the time required to update such a reference in a NERC Standard. Additionally, the DT is not specifying particular library models for other resources, so specifying a particular model for DER will invite challenges. Further, challenges with precisely defining and determining what a "successor model" is could potentially create more future reliability risks. The standard as currently written allows for additional future models of higher fidelity to be accommodated.
P157. We believe the development of new or modified Reliability Standards is an important corollary to NERC's ongoing effort to identify and register generator owners and operators of IBRs. Although NERC's registration changes will not at this time address IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, we believe APS's concerns	MOD-032 TOP-003 IRO-010	**Theme:** The responsible entity for IBR-DER data when there is no registered DP. Upon a decent amount of conversation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for

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regarding system-wide model validation is addressed in NERC's Reliability Guidelines and through the use of the EPRI DER Settings Database. We recognize that some distribution providers may not be able to provide a precise set of modeling data and parameters that accurately represent IBR-DERs in the aggregate. For these situations, NERC has provided a technical means to estimate in aggregating the needed IBR-DER modeling data and parameters (i.e., for the DER_A model) in the IBR-DER Data Collection Guideline. Further, NERC's 2021 Aggregate DER Model Verification Guideline provides transmission planners and planning coordinators with tools and techniques that can be adapted for their specific systems to verify that aggregate DER models (i.e., DER_A models) are a suitable representation of these resources in planning assessments. **Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models.**		collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." The use of the word "typical" is intentional to indicate the most likely entity based on the DT's broad understanding but allows flexibility per Requirement 1 for the PC/TPs to select a more appropriate entity or entities in their area based on regional or jurisdictional differences.
P161. "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal to provide additional specificity to explain coordination and keep up to date in a timely manner the verified data and models of	MOD-032 IRO-010 TOP-003	The proposed Milestone 3 Reliability Standards collectively address the Commission's directives in Order No. 901 paragraph 161.

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registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate in the system models. **Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model.** Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these resources in the system models. For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity		The Project 2022-02 DT modified MOD-032 to ensure it captures the uniform framework with modeling criteria, and necessary data exchange requirements for registered IBR, unregistered IBR, and DER (to include IBR-DER). Modifications in TOP-003 and IRO-010 are intended to promote consistency in models submitted for planning purposes and operations purposes so that entities responsible for planning and operating the BPS are all working from similar models that accurately represent the resources within their footprints. • A uniform modeling framework is established in the proposed MOD-032-2 through improvements to R1, R2, and R3 and Attachment 1. The inclusion of the ERO Unacceptable Models List (and additional revision process) and additional requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. Where appropriate, there are flexibilities built into this framework to accommodate differences in planning area modeling needs. • The PC and TP are allowed to require standard library models, but if user-written models satisfy usability criteria, and processes established through R1, R2, and R3 of the proposed MOD-032-2 standard, they are not prohibited. The framework explicitly allows for the submission of standard library models along with submission of user-written models which allows for the use of standard library models when combining neighboring transmission system models and Interconnection-wide models. If user written models are accepted, the PC and TP are required to share their usability criteria with other planning entities within the Interconnection upon request.

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responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives. NERC may implement this directive by modifying Reliability Standards MOD-032-1 and MOD-033-2 or by developing new Reliability Standards to establish requirements mandating an annual process to coordinate, validate, and keep up-to-date the transmission planning, operations, and interconnection-wide models."		• The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the proposed MOD-032-2 standard. While the TO would be the typical entity for providing unregistered IBR data and the DP would be the typical entity to provide DER data (as noted in Attachment 1 of proposed MOD-032-2), the DT recognized that there may be some variations as to whom might have the most accurate and usable data for unregistered resources in the planning area. Therefore, the DT modified the Requirement language to allow the PC and each of its TPs to identify the most appropriate entity to provide the data listed in Attachment 1 of proposed MOD-032-2. • Similarly, a determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System requires engineering judgment and the consideration of other material factors, which would not be prudent to prescribe in a Reliability Standard. Thus, Attachment 1 footnote 7 of proposed MOD-032-2 was added to explicitly allow PCs/TPs to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard). To the extent IBR modeling data is deemed necessary under IRO-010 and TOP-003, it should be consistent with modeling data provided for planning purposes. Therefore, the DT made changes to IRO-010 and TOP-003 to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes. Consistency in models is important to ensure BPS planners and operators are working from similar and high quality models; however, the DT recognized that operations entities may

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		require some adjustments from the model submitted for planning purposes to satisfy the needs in an operations environment. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, rather than Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection, so that entities may select the most representative model for the resource meeting PC/TP requirements (rather than mandating use of a defined set of models which may quickly become out-of-date). Models that are known to have fidelity issues are not to be submitted without technical justification. Specific fidelity/accuracy evaluations are beyond the scope of MOD-032, but are addressed in other proposed Milestone 3 Reliability Sstandards. The DT confirmed the link between these standards by requiring that models submitted under MOD-032 shall be the models verified under MOD-026, where available. System models developedvalidated under MOD-033 shall be developedperformed in accordance with data provided under MOD-032 and MOD-033. Regarding thate part of the directive to keep models up to date, MOD-032-1 already mandated a "schedule for submission of data at least once every 13 calendar months." This requirement is maintained in proposed MOD-032-2. System models will thus be built on updated data and models, which are verified and validated in accordance with the proposed MOD-033-2 and MOD-026-2 standards. With regards to that part of the p.161 directive addressing a "registered model designee" for building the Interconnection-wide cases, NERC considered the directive and concluded that the present ERO modeling

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		designee framework, with notable enhancements since 2023, presents an equally effective and efficient alternative to designating an entity on the NERC Compliance Registry to perform the tasks of Interconnection-wide model building. Further, the present framework, as enhanced since 2023, has distinct advantages over designating a responsible entity in that it maintains ongoing oversight of the Interconnection case building process, rather than compliance/audit-focused oversight with a retroactive focus. Additional explanation is provided below. **Registered Modeling Designee:** The current MOD-032-1 Requirement R4 requires each PC to make available models for its planning area provided under R2 to the Electric Reliability Organization (ERO) or its designee to support the creation of the Interconnection-wide cases. This is not changed in proposed MOD-032-2 R4. As noted above, proposed MOD-032-2 Requirement R1, Part 1.1 would require the PC and each of its TPs to identify the entity responsible for each required item in Attachment 1. That entity must provide the information under Requirement R2. A new Requirement R2, Part 2.2 has been added to require models provided under MOD-026 to be accepted by the TP, where available Requirement R3 requires notification from the PC or TP regarding technical concerns with the data submitted under Requirement R2. This improved framework for modeling contemplates coordination and model updates as needed by registered entities as models are collected to build the Interconnection-wide cases. As to who builds the Interconnction-wide base case model, the ERO has designated entities with a sufficient wide area view and focus on reliability for each Interconnection to perform this work. For the Texas Interconnection, the Texas Regional Entity performs this work in

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		coordination with ERCOT. For the Western Interconnection, the Western Electric Coordinating Council (WECC) performs this work. For the Eastern Interconnection, the Eastern Interconnection Reliability Assessment Group (ERAG) consisting of MRO, NPCC, RF, and SERC performs this work. The ERAG also performs the base-case model creator function for the Quebec Interconnection in Canada. As the ERO, NERC is responsible for overseeing and ensuring that these designated entities perform the proposed MOD-032-2 Requirement R4 activities. In 2023, the Officers Leadership Team of the ERO Enterprise approved the MOD-032 Designee process document. This process document reflects the maturation of this aspect of the ERO's activities and contains clauses and processes that require the designee for the Interconnection to perform specific duties. Each designee must have certain attributes, including a governance structure responsive to the needs of Planning Coordinators, with clear roles and responsibilities for model creation, transparency in data requirements, establishing timeframes for review cycles, and defining security and access to models. Certain core cases are required as part of this process, including core cases for the ERO for use in seasonal planning studies and event analyses. Other core cases are required for validating Interconnection Frequency Response obligations and event analyses. Lastly, the process requires the development of typical cases to support implementation of the TPL-001 standard. NERC or the Regional Entities may request additional specialized cases as needed. Designated entities have certain responsibilities under this framework, including developing a method for collecting data from all Planning Coordinators and developing and maintaining a case creation manual

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		including the process by which cases must be assembled, tested for quality, and tested for case fidelity according to ERO case quality metrics. NERC will perform an annual case quality assessment, and the designee must address any case model deficiencies identified by NERC. The process also contemplates feedback processes and processes for correcting cases or addressing recurring data or model errors with Planning Coordinators, among other controls, to ensure quality. Regarding the ERAG, there is also an Eastern Interconnection Regional Entity Agreement among MRO, NPCC, RF, and SERC[1]. In this agreement, there are provisions for oversight and coordination in how this group exercises its authority as the MOD-032 designee. Connections to MOD-032 are acknowledged, such as: • Oversight of the Multiregional Modeling Working Group[2] (MMWG, whose membership is comprised of one power flow representative and one dynamics representative from each of the Data Submitting Entities (comprised of Planning Coordinators or group of Planning Coordinators) and non-voting representatives as follows: one liaison representative each of the EI Regions and the ERAG Chair, a coordinator from each of the organizations that provides model development services to MMWG, and NERC and FERC staff liaisons. ○ The purpose of the MMWG is to coordinate, in a timely manner, the development of designated power flow and

1 EI-Regional-Entity-Agmt-Final-Signed.pdf

2 ERAG-MMWG-Charter-2024.pdf

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		dynamics simulation base case models that realistically simulate steady state and dynamic bulk electric system behavior of the Eastern Interconnection. ○ To ensure cases and models are done in a consistent fashion, the MMWG holds three annual meetings along with conference calls as needed. The MMWG roster includes a FERC liaison who can attend all meetings. The group maintains a case building procedure manual[3] that is used by its members. The manual contains a set of data checks that are performed on the steady state and dynamic cases. • Oversight of the Acceptable Model Working Group (AMWG)[4], which is comprised of: (1) Planning Coordinators or group of Planning Coordinators who are responsible for the development and maintenance of an Eastern Interconnection dynamic acceptable model list, and (2) RE and NERC staff who are responsible for coordination and facilitation. ○ The group was formed in 2023 and recently published the first version of its acceptable model list which was posted to the public ERAG website[5]. As models are removed from the acceptable list, the group develops an industry communication to begin removing those models from the annual set of cases.

[3] Microsoft Word - ERAG Base Case Release Procedure

[4] https://www.rfirst.org/wp-content/uploads/2023/10/ERAG_AcceptableModel_WorkingGroup_Charter.pdf

[5] www.erag.info

FERC Order No. 901 Directives		
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		○ Oversight includes review of all process changes made to the AMWG procedures to ensure consistency with the NERC case quality metrics. In addition, NERC further considered the following information provided by the MOD-032 Designee Group comprised of members from NERC and the Regional Entities: **MOD-032 Designee Group:** The electric grid is evolving at an unprecedented pace, driven by the rapid integration of inverter-based resources (IBRs), changing load characteristics, and emerging technologies. As the system transforms, the models we use to study and understand its behavior must also transform. We recognize the growing challenge of obtaining and coordinating accurate dynamic models for IBRs, including securing the appropriate parameters needed to ensure that simulation results reflect real-world system performance. Addressing these modeling challenges is essential to maintaining the reliability and resilience of the bulk power system and requires close collaboration, and the MOD-032 designees along with PCs are committed to and holding data providers accountable for model coordination and model quality. The MOD-032 designees are committed to ensuring that the model quality is maintained and there is a mechanism in place for the PC/TP to gather the appropriate information from the Generator Owners (GO). NERC facilitates the designee group of Regional Entity staff who are responsible for designee activities.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
		*** In summary, the proposed revisions to the standards addressed in Milestone 3 work, along with the ERO designated entity framework discussed above for building Interconnection-wide cases, address the concerns underlying the Commission's directive in paragraph 161 of Order No. 901 regarding the coordination, updating, and timely development of quality Interconnection-wide models that accurately represent the behavior of IBRs in the Interconnection. Further, this framework advances consistency in modeling used across planning and ERO assessment activities. NERC therefore submits that this framework represents an equally effective and efficient approach to addressing this part of the Commission's paragraph 161 directive to identify a registered modeling designee in the MOD-032 standard.
P226. "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	MOD-032 IRO-010 TOP-003	**Theme:** Sufficient timeframe. The DT felt that four years was an appropriate timeframe for the MOD-032, IRO-010, and TOP-003 implementation times. It is understood that based on what is required via MOD-032, industry would need two years to hold meetings with stakeholders to establish processes for collecting the needed models and data, and then an additional two years to update models based on the new requirements, etc. However, taking into consideration the FERC Order 901 implementation deadline of 2030, the DT settled on a three-year implementation time knowing that milestone 4 revisions still need to be implemented by 2030 and are dependent on the Milestone 3 implementation plan time. Three- year implementation plans were also selected for TOP-003 and IRO-010 to align potential new data requests under TOP-003 and IRO-010 with the expected data availability under MOD-032 processes.

FERC Order No. 901 Directives		
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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."		

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Exhibit D-1

Current MOD-032 Designee Process Document
(*for informational purposes only*)

ERO Enterprise Designation
MOD-032-1

This Reliability Standard MOD-032-1 process document is being made pursuant to the certain Federal Energy Regulatory Commission ("FERC")-approved Regional Delegation Agreements ("RDA"), between the North American Electric Reliability Corporation ("NERC") and each of, Midwest Reliability Organization ("MRO"), Northeast Power Coordinating Council, Inc. ("NPCC"), ReliabilityFirst ("RF"), SERC Reliability Corporation ("SERC"), Texas Reliability Entity, Inc. ("Texas RE"), and the Western Electricity Coordinating Council ("WECC"), respectively (together the "Regional Entities"). The purpose of this process document is to establish the necessary procedures the Regional Entities, participating as Designated Entities as further described below and in **Attachment 1**, perform in supporting NERC's efforts to fulfill its regulatory obligations under Reliability Standard MOD-032-1 (or its successor) and associated events analysis activities. Together, NERC, as the Electric Reliability Organization ("ERO") and the six Regional Entities are referred to as the ERO Enterprise.

Reliability Standard MOD-032-1, requires NERC to establish consistent modeling data requirements and reporting procedures necessary to develop planning horizon cases necessary to support NERC's analysis of the reliability, resiliency, and security of the interconnected transmission system. Requirement R4 states that, "[e]ach Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the [ERO] or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area." NERC is designating the MOD-032-1 "Designated Entity" responsibilities to the Regional Entities to support NERC in fulfilling its obligations under Requirement R4 given their expertise in their respective geographic jurisdictions as follows:

1) MRO, NPCC, RF, and SERC collectively perform the Interconnection-wide, base-case model creator function for the Eastern Interconnection as the Eastern Interconnection Reliability Assessment Group ("ERAG"). The base-case model creator function for the Québec Interconnection is included in the work performed by ERAG.
2) Texas RE, in coordination with ERCOT, will perform the Interconnection-wide, base-case model creator function for the Texas Interconnection.
3) WECC will perform the Interconnection-wide, base-case model creator function for the Western Interconnection.

As the ERO, NERC is responsible for overseeing and ensuring that the Designated Entities perform the MOD-32-1 Requirement R4 activities. NERC therefore maintains its discretion and authority to determine the accuracy, completeness, and overall satisfaction of the functions outlined in **Attachment 1.** Per the process in Attachment 1, each Designated Entity shall: (i) create the interconnection-wide power flow and dynamics cases that include all of the Planning Coordinators in their respective Interconnection; (ii) be responsible for developing the required modeling cases; and (iii) coordinate with NERC to address and document variations in Interconnection modeling practices and considerations in light of Reliability Standards TPL-001, MOD-032, MOD-033, and other applicable Standards. Please note, NERC and the Designee(s) shall collaborate on how best to address any NERC request pertaining to modeling which goes beyond information obtained or created under NERC Reliability Standards, the RDAs, and NERC Rules of Procedure ("ROP"). NERC and the Regional Entities shall hold a joint periodic meeting to collaborate on modeling activities. This shall include annually assessing **Attachment 1** at the final ERO Enterprise meeting

each year to discuss lessons learned and process updates for the coming year. This process document is subject to periodic review and change. Any revisions to this process shall be presented to the Operations Leadership Team ("OLT").

For the avoidance of doubt, the RDAs and ROP shall continue to govern all delegated activities, including managing Confidential Information pursuant to Section 1500 of the ROP. The relevant regulatory structure and governing documents in each Canadian Province shall continue to govern the activities in those respective jurisdictions. This Process Document does not modify the rights and obligations of NERC and the Regional Entities as otherwise outlined in the RDA and ROP or other governing documents.

Attachment 1 on the Following Page.

Attachment 1:

Designated Entity Functions and Attributes

This Attachment 1 outlines the requirements for each Designated Entity as referenced in the accompanying process document. Any capitalized terms not defined in this Attachment 1 shall have the same meaning ascribed to them in the process document.

The Designated Entities assigned by NERC as ERO under Reliability Standard MOD-032-1 Requirement R4 to support the creation of Interconnection-wide planning cases shall have the following attributes:

- A governance structure responsive to the needs of the Planning Coordinators for its Interconnection, Regional Entities, and NERC.
    - Clear definition of roles and responsibilities related to the creation of the models
    - Transparency regarding the development of data requirements, sampling, testing, data correction, and feedback to applicable stakeholders
    - Establish timeframes that allow for the review cycle
    - Define security and access related to models
- In coordination with the Planning Coordinators of the Interconnection, Regional Entities, and NERC, annually create and make available a specific set of powerflow and dynamics cases that include, but are not limited to, the cases identified below.

Core Cases[1] for the ERO:

- Upcoming[2] winter peak-load case – for seasonal planning studies (interregional) and event analyses, and as external models of outside world for operational planning studies.
- Upcoming summer peak-load case – for seasonal planning studies (interregional) and event analyses, and as external models of outside world for operational planning studies.
- Upcoming year low Inertia / low load case – for use in validation of Interconnection Frequency Response Obligations and event analyses.

Typical Cases[3] to Support Standard TPL-001-5.1 – Transmission System Planning Performance Requirements:

TPL 001-5.1 calls for the following cases to be available. Each Designated Entity, in collaboration with its constituent Planning Coordinators, may add additional cases as desired and choose which cases to build where latitude is given in the Standard. Since current case building practices and schedules vary among the Interconnections, a separate guidance document will be provided by NERC on case creation timing, as applicable.

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[1] Needed base cases for analyzing system events and testing frequency response obligations.

[2] Upcoming could be interpreted as Year 1

[3] ERO guidance for key years cited in Standard TPL-001-5.1, subject to enforcement July 1, 2023.

- Planning cases:
    - Planning case for year 1 or 2 system peak steady-state analysis[4]
    - Planning case for year 5 system peak steady-state analysis[5]
    - Planning case for near-term (1-5 years) system off-peak steady-state analysis[6]
    - Planning case for near-term (1-5 years) system peak stability analysis[7]
    - Planning case for near-term (1-5 years) system off-peak stability analysis[8]
    - Planning case for Long-term Transmission Planning Horizon system peak steady-state analysis[9]
    - Planning case for Long-term Transmission Planning Horizon system peak stability analysis[10]

Other cases and processes:

- Designated Entities shall have a process with appropriate controls consistent with Section 1500 of the ROP for identifying and vetting of qualified users of the powerflow and dynamics cases of the Interconnection. NERC, Regional Entities, Planning Coordinators, Reliability Coordinators, Transmission Operators, and Transmission Planners, within the Interconnection are pre-vetted users of the cases.
- Existing powerflow and dynamics cases shall be made available by the Designated Entity to NERC, the Regional Entities, Reliability Coordinators, Planning Coordinators, Transmission Operators, and Transmission Planners within the Interconnection under appropriate controls.
- NERC or Regional Entities may designate additional specialized cases; e.g., Year 10 off-peak load case with low inertia, high BPS-connected inverter-based resource, and representation of distributed energy resources (dynamics case, in particular). An example of special cases may include the following:
    - Year 5 low inertia/Minimum load case to produce the Frequency Measures 1, 2, and 4 of the Essential Reliability Taskforce for the NERC Long Term Reliability Assessment tracking and trending.
    - Upcoming summer short-circuit case – for use in specialized Inverter-Based Resources studies, event analysis, and designation of electromagnetic transient (EMT) zones. These would not be interconnection wide cases but collected from the PC or TO, depending on how they are currently being built.
    - Collection of EMT zones as designated by NERC, as needed

[4] Pursuant to R2.1.1 of TPL-001-4 and TPL-001-5.1
[5] Pursuant to R2.1.1 of TPL-001-4 and TPL-001-5.1
[6] Pursuant to R2.1.2 of TPL-001-4 and TPL-001-5.1
[7] Pursuant to R2.4.1 of TPL-001-4 and TPL-001-5.1
[8] Pursuant to R2.4.2 of TPL-001-4 and TPL-001-5.1
[9] Pursuant to R2.2.1 of TPL-001-4 and TPL-001-5.1
[10] Pursuant to R2.5 of TPL-001-4 and TPL-001-5.1

- EMT cases and any special cases beyond those listed will be requested by NERC or other Regional Entities with at least 60 days advanced written notice, provided that should a Designated Entity require additional time the relevant ERO Enterprise parties shall collaborate to determine the appropriate timeline.
- Designated Entities, in conjunction with the Reliability Coordinators, Balancing Authorities, Transmission Operators, Planning Coordinators, Regional Entities, and the ERO, shall develop a process for creating powerflow and dynamics cases for analysis of system events upon request of NERC or the Regional Entities.
    - These cases will be requested in accordance with the tenets of section 804, 807, and 808 of the NERC ROP. These cases are a distinctly separate effort from the annual case creation process, requiring additional manpower and time commitments. Such cases will typically only involve the entities in and surrounding the impacted area unless there are Interconnection-wide impacts (i.e., as inter-area oscillations).
- Designated Entities shall develop a process to ensure that all Planning Coordinators in their Interconnection and all system elements defined in the Planning Coordinator's modeling procedures[11] be included in the data collection process through a common method (e.g. MMWG case creation process) of collecting data and model(s).
- Designated Entities shall develop[12] and maintain a case creation manual for the Interconnection, including the process by which the designated cases must be assembled, tested for quality (e.g., MOD-033 or its successor), and tested for case fidelity (ERO Metric I[13]). NERC will conduct an annual case quality assessment compared to the criteria in this Attachment. The Designee shall have a process to address any case quality deficiencies identified by NERC. The Designated Entity shall collaborate with NERC to address any case and/or process deficiencies.
- Designated Entities shall develop a feedback process to incorporate improvements identified in NERC's independent modeling assessments on Interconnection-wide base cases. Any identified issues must be addressed by the Designated Entity in coordination with the asset/model owners.
- Designated Entities shall develop a feedback process including the Planning Coordinators of the Interconnection and their constituent equipment owners and operators to prevent recurring data or models problems found during case creation or quality and validation testing. The Designated Entity shall work with the Planning Coordinator on any recurring data or model errors in a timely manner.
- Designated Entities shall develop and maintain a list of acceptable dynamics models[14] for representing equipment in the base cases. The list shall be made available to all entities submitting models and shall be updated regularly to reflect changing industry practices. NERC may provide input such as the use of preferred models or may establish additional modeling requirements that shall be implemented by the Designated Entities. The Designated Entity will phase out models NERC has determined "unacceptable" in a timely manner.

[11] Pursuant to R1 of MOD-032

[12] The designee can either develop or adopt an existing regional or multi-regional process manual.

[13] https://www.nerc.com/pa/RAPA/ModelAssessment/ModAssessments/2022_Case_Quality_Metrics_Assessment-FINAL.pdf

[14] These lists will be maintained in a timely manner in collaboration with similar lists in the region(s).

- Designated Entities shall have a change-control process for dynamics models and/or parameters requiring appropriate documentation, with a subject matter expert peer group[15] to screen proposed changes.
- Designated Entities shall have a process for correcting cases for current or future years, created in the latest case creation cycle, that are already in use. The process shall include:
    - Coordination with the involved Planning Coordinator(s) and equipment owner(s) to resolve and correct problems found.
    - Timely posting of modifications made to cases to correct problems.
    - A method to notify case recipients of problems and solutions to known case recipients.

[15] Regional or Interconnection-wide.

Revision History

Table 1: Revision History		
Version	**Date**	**Modification**
0	01/2015	First designations were formally documented via individual letters
1	01/2023	First ERO Enterprise-wide designation as approved by the ERO Operations Leadership Team

Table 2: Document Ownership		
Document Owner	**Author**	**Department**
Advanced System Analytics, Modeling & Security	**Advanced System Analytics, Modeling & Security Staff**	**Advanced System Analytics, Modeling & Security**

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Exhibit E

Technical Rationale

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Technical Rationale

NERC Project 2022-02 | MOD-032-2, TOP-003-8, and IRO-010-6
September 2025

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. It should be noted that Generator Owner (GO) applicability includes both Category 1 GO and Category 2 GO consistent with proposed revisions to the definitions of those terms developed under Project 2024-01 Rules of Procedure Definitions Alignment.

Additionally, the drafting team (DT) reviewed the dual applicability to Planning Authority (PA) and Planning Coordinator and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria are updated to use only a single term. The posted "Appendix 5B: Statement of Compliance Registry Criteria," dated June 27, 2024, still uses both terms and, arguably, the PA term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the DT excluded the explanatory language from MOD-032-2 Applicability Section.

Rationale for Distributed Energy Resource (DER) Definition

The DT has proposed that a definition for DER be added to the *NERC Glossary of Terms used in Reliability Standards* (NERC Glossary of Terms). The approved standard authorization request (SAR) to revise MOD-032, submitted December 2021, noted that "it may be needed (based on the discretion of the DT) to add a definition for 'Distributed Energy Resource (DER)' to the NERC Glossary of Terms" in conjunction with adding DER data to Attachment 1, the main purpose of this SAR.[1] The DT found it necessary to draft a DER definition to clarify the usage of this term within the standard. Further, the DT recognized benefits of a NERC Glossary of Terms definition to bring alignment and consistency of term usage across Reliability Standards. Additionally, the term Inverter-Based Resource (IBR) was recently defined in the NERC Glossary of Terms under Project 2020-06 for a similar reason. Finally, the DT was comprised of team members with adequate experience to propose a definition, including members of the NERC SPIDERWG and IEEE 1547 working group.

The DT proposes to define Distributed Energy Resource (DER) as follows:

"A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system."

[1] SAR title "MOD-032-1 Data for Power System Modeling and Analysis", submitted 12/15/2021. Available at: https://www.nerc.com/pa/Stand/Project202202ModificationstoTPL00151andMOD0321DL/2022-02_MOD-032%20SAR%20SPIDERWG_020122.pdf

In developing this definition, the DT considered various DER definitions utilized in the industry and discussed in the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Terms and Definitions Working Document, including the six other definitions described in Appendix D that were not adopted by SPIDERWG. Through this review, the DT determined each of these seven definitions would benefit from refinement to be most suitable for application in MOD-032 and future reliability standards more broadly. It is expected that most reliability standard revision proposals related to DERs would originate from the SPIDERWG. Thus, the DT's intent was to propose a DER definition that aligned with the SPIDERWG working definition, which explicitly excludes demand response and clarifies what is in scope and out of scope with respect to where a DER is connected, rather than the technology type. The DT's concurrence in excluding demand response from the definition of DER is due to demand response characteristics that are typically reflected in base case study assumptions rather than requiring explicit modeling within reliability simulations.

The DT considered adopting a voltage threshold to define distribution. However, industry generally differentiates transmission from distribution based on the functional use of the system rather than technical specifications (e.g., voltage, active power, etc.). Setting aside the Bulk Electric System, that has a NERC definition, defining electric facilities as either transmission or distribution is often based on State law or regulations, ISO/RTO tariff, and/or utility tariffs. There are no conflicts in how applicable entities define distribution and transmission facilities for a given region, even if those definitions vary from region to region. Additionally, the DT considered an active power threshold to define DER and concluded that DER technologies can vary in size, and a threshold might inappropriately exclude technologies that are DER[2]. At the same time, the DT understands that certain applications of DER data, for instance determining when or how a Transmission Planning (TP) or Planning Coordinator (PC) includes DERs into planning processes (e.g., TPL-001), may include active power or other TP or PC defined thresholds.

The DT considered defining DER based on the resource not being connected to the Bulk Power System (BPS), similar to the IEEE 1547-2018 definition that uses "not directly connected to the BPS" to describe DERs. However, the NERC Glossary of Terms definition of BPS does not provide specificity that would enhance a definition of DER beyond an undefined term that is generally used in industry. The phrase "distribution system" was selected to expressly describe the type of electric facilities that would cause a resource to be defined as a DER, if interconnected to those facilities.

The DT recognizes that "distribution system" is not defined in the NERC Glossary of Terms and that the SPIDERWG proposed a definition.[3] The DT reviewed the SPIDERWG definition and concluded that it would not clarify the term DER. The SPIDERWG use of the term "transmission-distribution" interface within a definition of "distribution system" could be considered a circular reference that causes ambiguity. The DT is not proposing a definition for distribution system given any proposed definition could be of limited benefit for clarifying the proposed definition for DER.

[2] NERC has published a study recommending that a zero MVA threshold be used when collecting DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

[3] SPIDERWG definition of "distribution system": The electrical facilities that are located behind a transmission-distribution transformer that serves multiple end-use customers.
https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

Below is a summary of the rationale for the DT departing from each of the seven definitions when proposing a new DER definition.

SPIDERWG definition
After considering the SPIDERWG definition, the DT determined it provided a useful foundation but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term included transient types of DER power beyond generation and storage, and it included sources of back-up power that would have no potential grid impacts.

The DT chose to refer to a generator or storage technology specifically, rather than use the SPIDERWG language of "source", to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.). A DER can use various technologies including synchronous machines, induction machines, and power inverters/converters (i.e., IBR). Different types of DERs can utilize a wide range of energy sources including, but not limited to, natural gas, diesel, hydro, storage, wind, and solar. Additionally, the DT intention was to ensure that the scope included facilities "connected behind the meter of an end use customer" that may export Real Power to the power system or offset Real Power load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load. While not finalized, it is the drafting team's understanding that this determination is consistent with recent proceeding from the IEEE 1547 revision Working Group. To exclude transmission connected load customers that have onsite generation or storage resources, the DER definition clarifies that the behind-the-meter customer "is supplied from a distribution system".

The DT included the language "in non-isolated parallel operation with the Bulk-Power System" to indicate that a distributed energy resource with potential BPS reliability impacts is only one that has electrical connectivity to the BPS. A resource that is only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BPS and, therefore, is not of interest from a BPS-reliability perspective. The DT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry. The DT intentionally avoided the term "directly connected" to differentiate electrical connectivity from an electrical connection point. The phrase "connected to the distribution system" speaks to electrical connectivity and the subsequent phrase "including one connected behind the meter of an end use customer" clarifies this connectivity includes a resource directly connected to a customer system (i.e., behind the meter).

IEEE 1547-2018
The DT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the issues identified above. The DT incorporated the explicit reference to generation and storage aspect of the IEEE definition. Further, the IEEE concept of "capable of exporting active power to an EPS" informed the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the DT definition.

At the same time, the DT did not view the IEEE definition as suitable for the DT's intended use as written. The IEEE term qualifies the DER connection point as "not directly connected to a bulk power system" which the DT viewed as potentially ambiguous. Instead, the DT opted for the "connected to a distribution system" language to point to the electric system location, and how facilities at that location are classified, as a key concept in differentiating DERs from other generators and energy storage technology. The DT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a NERC Glossary of Terms DER definition.

Federal Energy Regulatory Commission (FERC) Energy Primer
The DT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability use cases, the DT and SPIDERWG definitions target sources of electric power, with the DT narrowing this definition to be only sources "capable of providing Real Rower." After considering the FERC definition, the DT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)
NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the DT concluded it is too broad.

NERC DERTF
The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the DT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric System" which the DT views as overly broad.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be based on California legislation and includes energy efficiency, EVs, demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the NERC Glossary of Terms.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition's exclusion of a large portion of DER (i.e., retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study.

Figure 1 below provides a graphic illustration of the DER definition and the intended scope of facilities that would fall under the proposed definition. Figure 2 below shows that the proposed DER and IBR definitions are compatible, but distinct. Some resources may be classified as a DER, but not an IBR; some resources may be classified as an IBR, but not a DER; some resources may be classified as both a DER and an IBR. Rather than separately define IBR-DER, the DT suggests IBR-DER should be used to reference those devices meeting both the definition of IBR and the definition of DER, as demonstrated by the overlapping area of Figure 2. This relationship between the definitions and the existence of non-IBR storage solutions informed the phrasing of "generator and energy storage technology" to ensure all generators and all storage devices

are included, even if they do not meet the definition of IBR. Note that in Figure 2, "distribution-connected" is shorthand for connected to the distribution system and "bulk system-connected" refers to resources connected to the transmission system.

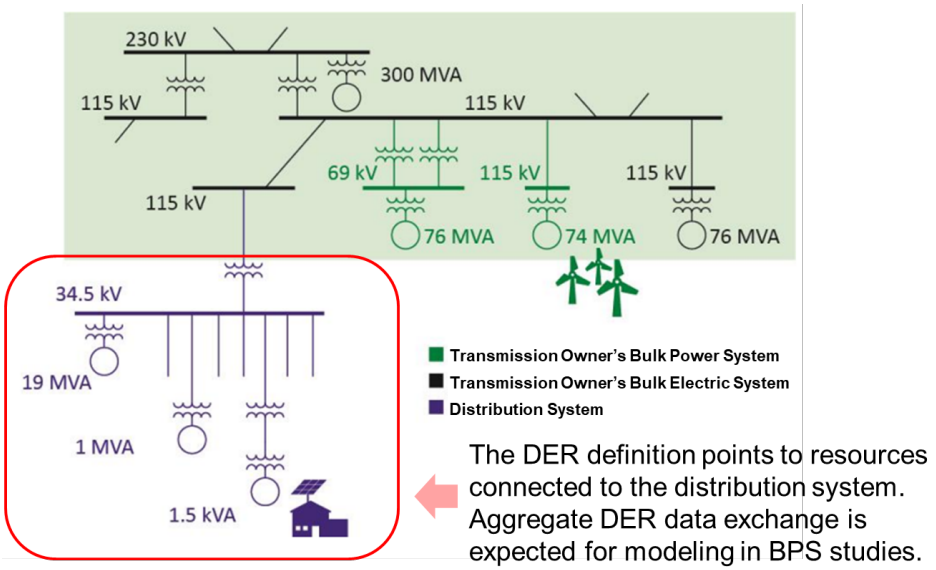


Figure 1: DER Definition Illustration

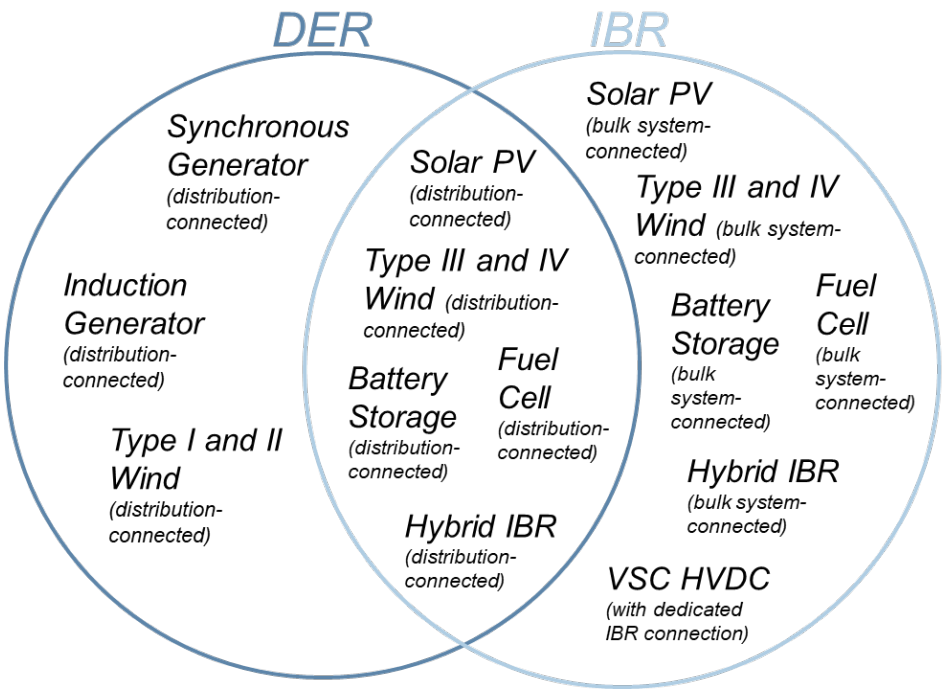


Figure 2: DER and IBR Definition Compatibility

Rationale for Modifications to Requirement R1

Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the "entity" to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement. Such flexibility could allow the TP or PC to directly estimate data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes and aggregated DERs connected to unregistered Distribution Providers based on any information received in accordance with their data requirements and reporting procedures. As an example, data received from DPs in the area that can be assumed to have similar DER adoption profiles. FERC Order 901 uses the phrase "unregistered IBR" but given this is an undefined term and the drafting team received opposition to explaining that term in a footnote, the phrase was replaced in the standard with "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes." This is the intent of all further references to "unregistered IBR" in this technical rationale.

FERC Order 901 directs NERC to develop reliability standards that require "the use of approved industry generic library IBR models".[4] However, pre-defining a limited set of models (i.e., a library of models) that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To align with industry practices while addressing the directives of the FERC Order, the DT referenced standard library models incorporated within software as well as usability requirements for user-defined models (where accepted) in Requirement R1, Part 1.4, rather than defining an inclusive model library. The DT supports the approach and views it as aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 and June 3-5 NERC Industry Engagement Workshops.[5][6] For instance, Order 901 P125 requires "the sole use of nation-wide approved component generic library models" whereas workshop participants raised issues surrounding timelines for approving library models that reflect new IBR products, the accuracy of library models for certain products, timelines associated with updating library models, and referencing a document outside of the standard that could be changed by a process also outside the standard, among other issues.

[4] FERC Order 901 at Paragraph 122.
[5] NERC Industry Engagement Workshop–Reliable IBR Integration and Milestone 3 of FERC Order 901 Agenda
[6] Milestone 3 of FERC Order 901 NERC Industry Engagement Workshop June 3-4 PowerPoint

To address these concerns, Requirement R1, Part 1.4 includes requirements for the PC/TP to specify submission of standard library dynamic models, user-defined models, or both. The phrase user-defined models should be considered interchangeable with user-written models, equipment-specific models, and other such terms. The phrase "user-defined models" was used in MOD-032-2 based on language in FERC Order 901.[7] Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. The DT also explicitly ensured PC/TP authority to require submission of both model types, if deemed necessary. Requirement R1, Part 1.4.2 is responsive to FERC concerns about model usability and non-convergence by requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions.

Rationale for Modifications to Requirement R2

Requirement R2 was modified to require estimation of modeling data if the functional entity required to provide it (typically the Transmission Owner or Distribution Provider) is unable to gather the required data. FERC Order 901 requires the provision of data related to unregistered-IBR and IBR-DER that in the aggregate have a material impact on the BPS.[8] If the data is estimated, Requirement R2 Part 2.1 also requires the entity to provide an explanation of the limitations of the estimated data and the method used for estimation in line with the Order 901 directives.[9] The requirement language intentionally uses the phrase "unable to gather" to mirror the FERC Order 901 language. Limitations of the estimated data is intended to capture both limitations of the availability of data (including instances where there are legal or contractual prohibitions on requesting certain data, no mechanism to enforce collection, or incomplete records of what is connected) and limitations of any data provided (including partially missing or suspect data).

The exact method used for estimation is intentionally left open given the varying levels of data available across the ERO footprint. A few possible examples include:

- A full list of DERs broken down by resource type with limited fields missing and assumed based on other characteristics.
- Real Power capability by resource type with approximate percentage of the resource compliance with various IEEE 1547 versions used for dynamic performance assumptions (known or assumed based on installation date).
- Count of resources by resource type with average size used to estimate Real Power capability.
- Derive values for unregistered DPs based on average of registered DPs in the area (scaled based on total system size).

[7] FERC Order 901 at P124
[8] FERC Order 901 at P104 and P105
[9] FERC Order 901 P104: "if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation."

- Solar capability estimated based on satellite imagery of rooftops.
- Assumptions of regional/national average IBR-DER penetration levels.

Additional guidance for DER estimation can be found in NERC SPIDERWG Reliability Guidelines on the topic.[10]

The DT views the introduction of this estimation provision as alleviating previously expressed compliance obligation concerns around challenges in collecting data for DERs connected to unregistered entities. Further, the addition of compliance abeyance language for the estimation process provides entities the opportunity to hone their estimation process without risk of penalty (provided they proceed in good faith). The approach directed by FERC is flexible as to whether the underlying unregistered IBR and DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP and TO applying a combination of approaches to source the data. The PC and TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

While the FERC Order 901 directives only addressed IBR-DER, meaning that DER technologies based on induction generators or synchronous generators are not explicitly addressed, Project 2022-02 is also assigned a SAR that requires DERs to be addressed in MOD-032 more generally, and the inclusion of all DERs in this revision of the standard removes the need for a second modification under this project. The DT found it practical to have a consistent estimation framework applicable for all DER technologies when DER data cannot be gathered. Therefore, Requirement R2 was intentionally written to have requirements for estimating DER data regardless of the technology type, when an applicable entity is unable to gather the data. The approach FERC directed NERC to use forms the basis for this uniform approach.

Given the challenges with collecting complete and accurate DER data, the DT would still recommend that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would delay the project beyond the FERC Order 901 Milestone 3 timeline. The DT considered adding "UFLS-Only Distribution Provider" to MOD-032-2 applicability to reduce (but not necessarily eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, the UFLS-Only Distribution Provider can only be obligated to provide data directly associated with UFLS programs (essentially the data identified in Attachment 1 Dynamics Column 10b). Provision of such data in the absence of the other DER data identified in Attachment 1 would not be particularly useful for planners.

Requirement R2, Part 2.2 was added to confirm the relationship and consistency between MOD-026 and MOD-032 indicated in FERC Order 901 Paragraph 143[11]. The DT believes that the intent of FERC Order 901

[10] Reliability Guidelines, Security Guidelines, Technical Reference Documents, and White Papers

[11] FERC Order 901 P143: ""Regarding EPRI's recommendation to require appropriately parameterized plant models, we agree that the model verification process of an IBR model should include steps to ensure that responsible entities provide both verified and appropriately parameterized models. Additionally, we agree with IRC's recommendation that the plant model verification process should include

is to ensure that accurate (validated and verified) models are collected under MOD-032. However, facility models submitted under MOD-032 are often submitted before physical validation can be completed (e.g., for planned facilities). Part 2.2 requires the model submitted by the functional entity be the model that was verified and validated (and accepted by the TP) in accordance with MOD-026, if available.

Requirement R2, Part 2.3 introduces a reference to the Unacceptable Models List (UML) maintained by the ERO. The DT concluded that it would be most appropriate for NERC to maintain the UML as a separate document that could be updated more quickly and frequently than the standard development process. However, any changes to the process for modifying the UML, that is incorporated into MOD-032-2 as a supporting document, would need to be approved through the standard development process.

It is also recognized that models on the UML may be the best available for some generators, particularly for some synchronous generators and for units manufactured by companies that are no longer in business. Part 2.3 allows for the submission of such a model if accompanied by a technical rationale justifying its use. The requirement does not intend any specific level of scrutiny for this rationale, but it also does not prevent the PC or TP from identifying technical concerns with the model or the rationale per Requirement R3. This rationale could include notation of prior usage for synchronous generation as well as models that have been recently added to the UML without time to procure an updated model prior to reporting. A MOD-032 supporting document defines the process for modifying the UML as a sufficient safeguard to prevent arbitrary or unvetted modifications being made to the UML.

Rationale for Modifications to Requirement R3

Requirement R3, Part 3.1 was modified to include the phrase “that is responsive to the technical concern”. The ultimate intent of R3 is to resolve technical concerns that are identified by the PC or TP. However, model providers may not always be able to know that their update or explanation will resolve the planner’s technical concern. The intent of this addition is to convey that the model provider’s obligation does not simply end with providing a response, but further information exchanges between the planner and model provider may be necessary to resolve the technical concern.

Rationale for Modifications to Attachment 1

Data items specific to IBRs and DERs were added to MOD-032-2 Attachment 1: Data Reporting Requirements.

The DT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with items are only presented in one column (i.e., some sub-bullets are only listed in the “steady state” column even though the data is also relevant to “dynamics” and/or “short circuit”). This long-standing approach was made explicit in footnote 1 of the MOD-032-2 Reliability Standard.

requirements for equipment to be represented as installed in the field. While we decline to include this level of detail in the directive to NERC, we nonetheless direct NERC to establish a standard uniform model verification process. A uniform model verification process will ensure that all entities use the same set of minimum requirements to verify that all generation resource (i.e., synchronous and non-synchronous) models are complete and that the models accurately represent the dynamic behavior of all generation resources at a sufficient level of fidelity for Bulk-Power System planners and operators to perform valid interconnection-wide, planning, and operational studies. Therefore, we direct NERC to define the model verification process and to require consistency among the model verification processes for existing Reliability Standards (e.g., FAC-002, MOD-026, and MOD-027) and any new or modified Reliability Standards.”

The format of Attachment 1 was modified to minimize replicating footnotes applicable to multiple items by adding a new footnotes section (Attachment 1 Data Reporting Requirements Footnotes) to the document. Along with the reformatting, language was added to the introductory paragraph to clarify that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The expectation is that existing reporting requirements will remain the same, but previously implied flexibility is now explicitly granted as it is critical for regional consideration of the appropriate entities to provide information for unregistered IBR and DER.

Modifications for IBR

To incorporate IBR within Attachment 1, "and storage units" was added to generating units in the steady-state column under item 3. "Generating units" already incorporates IBR generators such as solar and wind. Storage is typically not classified as a generation resource because it has no primary energy source and consumes more energy than it injects when considering losses. Therefore, the DT found it necessary to include storage explicitly. Footnote 4, associated with "Generating units and storage", was also updated to explicitly identify IBR as an applicable technology for the item and remove pumped storage now that storage is explicitly identified.

The dynamics column was updated to replace "photovoltaic systems" (PV) with "Inverter-Based Resources" under item 7. IBR encompasses PV, resulting in PV technology still being included under this new item.
The three following sub-items were added to dynamics item 7 based on specific language from the FERC Order 901, Paragraph 141.[12]

- IBR capabilities related to momentary cessation,
- Tripping, and
- Ride-through

"Frequency control" was added as a sub-item because frequency response of IBR is important for studying system reliability. For instance, a 2024 NERC Lessons Learned report shows how IBR frequency response can affect system performance.[13] Frequency control encompasses primary frequency response, fast frequency response (e.g., IEEE 2800-2022, Subclause 6.2), and potentially other frequency responsive controls (e.g., "grid-forming" virtual synchronous machine controls).

"Voltage control" was added to encompass reactive power and voltage control that may affect the dynamic or steady state performance of the plant. NERC's Level 3 Alert on Inverter-Based Resource Performance and Modeling, issued May 2025, contains Essential Action #1 indicating the importance of voltage control performance for normal and post-disturbance operations.[14]

[12] FERC Order 901, P141 states that IBR and IBR-DER data must include "momentary cessation and/or tripping, and all ride through behavior."
[13] NERC, Lessons learned, Incorrect IBR Primary Frequency Response Logic Caused Negative ACE. Available at: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20240501_Incorrect_IBR_Primary_Frequency_Response_Logic_Caused_Negative_ACE.pdf
[14] NERC, IBR Performance and Modeling, Level 3 Alert. May 2025. Available at: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/Level%203%20Alert%20Essential%20Actions%20IBR%20Performance%20and%20Modeling.pdf

In order to clarify dynamics item 6, "wind plant model", to not overlap with the new IBR item 7, type 1 and type 2 wind turbines are specifically called out under item 6. These technologies are not IBR.

Footnote 5 indicates that the PC/TP data requirements and reporting procedures need to account for IBRs that are not DERs and do not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. It also indicates that the TO is typically responsible for such data.

Modifications for DERs

Item 9, "Aggregate Distributed Energy Resource (DER) data" was added to the steady state column with location, real power capability, and DER type (solar, battery, diesel generator, etc.) specified as required subitems. The DT selected these subitems as the minimum information needed to use data and make assumptions for power system modeling and analysis; the PC/TP have the authority to request additional data items as deemed necessary.

The intent is that relevant DER data be available and represented in models of the interconnected transmission system consistent with the NERC approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum information needed to reasonably represent DER in transmission system models. "Aggregate DER" is specified in item 9 to indicate aggregate DER data, rather than individual DER facilities, would be represented in most PC/TP study models.[15] The word "aggregate" was specifically added to Attachment 1 to clarify this point based on industry comments and to align with FERC Order 901. However, Requirement R1 provides the PC and TP great flexibility in developing data requirements and reporting procedures that align with local practices and needs, in addition to the required items listed in the Requirement R1 Parts. Given industry comments on DER data availability, and FERC Order 901 directives, a process is needed for estimating DER data when an entity is unable to gather it. The process for estimating those values is referenced in Requirement R2, Part 2.1.

Footnote 3, associated with "aggregate demand", was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DERs is not consistent with a modeling framework that explicitly represents DERs. Given the allowance for a PC/TP to specify a threshold per footnote 7, they may confirm gross demand can be assumed to be equivalent to net demand when the difference is under that established threshold. This should be clarified in the level of detail of information requested in Requirement R1, Part 1.2.2.

Dynamics item 5, previously "demand", was updated to be "aggregate demand" to be consistent with the steady state column and general industry practices of modeling load dynamics for aggregate demand (e.g., composite load model).

[15] In certain circumstances (e.g., a very large DER), a TP or PC may decide to represent the individual DER. However, the DT anticipates most DER information will be aggregated based on PC and TP planning practices.

Dynamics item 10 was updated to include "Aggregate Distributed Energy Resource (DER) data" along with the subitems: "parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control"; and "indication whether DERs are subject to tripping in conjunction with UFLS or UVLS".

Momentary cessation, tripping, and ride-through of aggregate DERs is needed for dynamics studies. For instance, NERC's Lessons Learned, LL20220401 "Distributed Energy Resource Performance Characteristics during a Disturbance" provided information following the loss of 300 MW of DERs following a system fault. The report indicated that:

> "There is a need to understand how distribution system connected generation, and loads will behave and how they can accurately be modeled under expected system contingencies. Entities should know the behavioral characteristics of DER inverters on their system (both new and old) as well as their number, capabilities, and locations and then report that information to their Balancing Authorities and Reliability Coordinators so their models can be accurate".

Voltage control of DERs can alter the exchange of reactive power between distribution and transmission systems and may affect the results of reliability studies. Examples are described in the approved Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources.

Frequency control must be accounted for because DER interconnection under different standards (e.g., IEEE 1547-2003 versus IEEE 1547-2018) have different frequency response characteristics that may affect dynamics study results. Frequency control in this case typically refers to the frequency-droop characteristic outlined in IEEE 1547-2018, Subclause 6.5.2.7 and adopted in many jurisdictions. However, should other DER frequency controls become common in industry, those would also fall under this category.

As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DERs subject to each UVLS/UFLS tripping stage should be identified.

In response to comments, the DT added Footnote 7, which explicitly confirms the PC/TPs discretion to specify aggregation thresholds below which they do not consider DER data necessary to collect. Based on the 0 MVA threshold recommendation noted previously, this threshold should only be established following consideration of that DER Modeling Study Report[16].

Inferring DER Capabilities

[16] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

Item 10 in the dynamics column indicates that aggregate DER dynamics modeling data may need to be inferred due to data availability and practical limitations. As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DERs may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DERs installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate Ride-through characteristic representation for DERs in that area could be inferred by the in-service date of the DERs. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

Entity responsibilities and coordination

Footnote 6 indicates that the PC/TP data requirements and reporting procedures need to account for situations where DERs are connected to the system of an unregistered DP. When a DER is connected through a registered DP (directly connected to that DP, connected to an unregistered DP that is connected to that DP, or behind the meter of an end-use customer of either) that DP is the typical responsible entity for collecting and providing the DER data. Further, the TO would be the typical responsible entity if there is no system owned by a registered DP between the DER connection point and TO system. This clarification is necessary to reduce the possibility of DERs on the system being unaccounted for by any entity. The DT was responsible for the FERC Order 901 directive requiring an entity to be identified when DERs had no registered DP. It is possible that a company that is a registered Generator Owner may also own resources that do not meet the criteria for registration. That would not change the responsible entity identified per R1, though the owner is encouraged to provide all relevant data to that responsible entity. This point applies broadly, where nothing in the standard is intended to preclude coordination among entities to make sure the responsible entity has the best available information to provide.

The PC/TP may have access to sufficient data for modeling certain DERs through alternative means (e.g., direct registration of DERs or DER aggregators in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data, but care will be needed to ensure DERs are not double counted. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DERs that are excluded from the DP/TO obligation for providing DER modeling data. This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its PC and TP under Requirement R1.

It should be noted that the MOD-032-2 modifications do not change the classification of unregistered IBRs or DERs to become BES facilities subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered entities (typically DPs or TOs if identified as the responsible entity by the PC/TP) to provide basic information about unregistered IBRs or DERs that are connected to their systems so they can be properly represented in Interconnection-wide cases. There are already existing requirements for such entities to provide information about load connected to their systems. Like load,

unregistered IBRs and DERs are not generally considered to be BES facilities. However, BES reliability assessments require an accurate representation of aggregate load, unregistered IBR, and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient data is available to the PC/TP so that appropriate unregistered IBR and DER representations can be included in their BES reliability assessments as required by FERC Order 901 and system planning needs.

IRO-010-6 – Reliability Coordinator Data Specification and Collection; and TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

The DT reviewed existing IRO-010 and TOP-003 versions and found that both standards had broad requirements language that encompassed generation and storage resources, including IBR as deemed necessary by the RC/TOP/BA. Nevertheless, to ensure no ambiguity that FERC Order 901 requirements are met, the DT included explicit references to IBR-specific data and parameters and pointed to the uniform framework through an alignment between planning and operations models.

Rationale for modifications to add "IBR-specific data and parameters"

The phrase "IBR-specific data and parameters" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.1
- TOP-003-8 Requirement R1, Part 1.1
- TOP-003-8 Requirement R2, Part 2.1

These modifications were made in response to FERC Order 901 directives related to the inclusion of IBRs in operations models.[17] The phrase "IBR-specific data and parameters" in the revised IRO-010-06 and TOP-003-8 is intended to reflect what FERC describes in the order as "IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions". Given that the definition of IBR has no voltage threshold, the addition of IBR-specific data and parameters is inclusive of IBR-DER as referenced in FERC Order 901 and demonstrated by the overlapping area of Figure 2.

Rationale for modifications to add reference to consistency with planning models

"Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operation purposes, as applicable" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R2, Part 2.5.3

These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework, though additional standards or regional requirements may apply. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Simulation time constraints in an online operations environment may warrant a reduced model structure complexity; such models may differ from, but should still be consistent with, more complex modeling that is submitted under MOD-032. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. For example, consistent models would not be appropriate if an

[17] FERC Order 901 Paragraph 122 and Paragraph 161

update was made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation.

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Exhibit F

Unacceptable Models List

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ERO Unacceptable Models List

Project 2022-02 Uniform Modeling Framework for IBR

September 2025

RELIABILITY | RESILIENCE | SECURITY






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Overview/Introduction

FERC issued Order No. 901 on October 23, 2023, directing "NERC to develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."

Proposed Reliability Standard MOD-032-2 addresses the reliability issue identified by FERC in Order No. 901 in a manner that considers advancements in user written models since the issuance of Order No. 901, perspectives of planning entities across North America, and the historical practice of the ERO, which has been to maintain a use of unacceptable models, rather than acceptable models, due to the practical difficulties of keeping an acceptable model library up to date in a timely manner.

Reliability Standard MOD-032-2 requires the Planning Coordinator and Transmission Planner to include specifications addressing the use of standard library models, user-written models meeting certain minimum usability requirements to minimize the risk of non-convergence, or both. To minimize the use of models with known deficiencies, Transmission Planners and Planning Coordinators must also include provisions to require any entity submitted on the Unacceptable Model List to include a technical rationale supporting its use.

The Unacceptable Models List identifies models that are generally considered not acceptable for purposes of model submissions under the MOD-032, TOP-003, and IRO-010 Reliability Standards due to identified issues with usability or accuracy impacting the ability to develop planning or operational horizon cases necessary to support analysis of the reliability of the interconnected transmission system. However, it is recognized that the use of such models may be appropriate in some cases, such as where there is no feasible means for procuring an alternative model that may better represent the behavior of legacy equipment. Any use of such models must include a technical rationale supporting its use.

Disclaimers

Interconnection-wide modeling requirements may differ from the requirements of specialized studies dedicated to a particular technical objective. Thus, models deemed acceptable for planning purposes may be deemed unacceptable by a receiving entity for certain operations applications.

Updates to the Unacceptable Models List

Refer to the Supporting Document section of MOD-032.

Chapter 1: Unacceptable Models List

Models that have been identified as unacceptable are listed in Table 1 below. Revisions to this list may be made in accordance with the process described in the Supporting Document section of the MOD-032 standard.

Table 1: Unacceptable Model List		
Known Unacceptable Model Name	**Model Description**	**Effective**
Renewable Energy Models		
WT3G1, WT3G2, wt3g	Generic Type 3 WTG Generator/Converter Model - Doubly-fed induction generator	Effective Date of MOD-032-2
WT4G1, WT4G2, wt4g	Generic Type 4 WTG Generator/Converter Model - Variable speed generator with full converter	Effective Date of MOD-032-2
WT3E1, wt3e	Generic Type 3 WTG Electrical Control Model	Effective Date of MOD-032-2
WT4E1, WT4E2, wt4e	Generic Type 4 WTG Electrical Control Model	Effective Date of MOD-032-2
WT3T1, wt3t	Generic Type 3 WTG Turbine Model	Effective Date of MOD-032-2
WT3P1, wt3p	Generic Type 3 WTG Pitch Control Model	Effective Date of MOD-032-2
WT12A1, wt1p, wt2p	Generic Type 1 and 2 WTG Pitch Control Model	Effective Date of MOD-032-2
WT4E1, wt4t	Generic Type 4 WTG Power Converter Model	Effective Date of MOD-032-2
wt4p	Generic Type 4 Pitch Control Model	Effective Date of MOD-032-2
REECB1, REECBU1, reec_b	Generic Phase 2 PV Electrical Controls Model	Effective Date of MOD-032-2
Machine Models		
GENSAL, gensal	Salient Pole Generator Model (IEEE Std 1110 §5.3.1 Model 2.1)	Effective Date of MOD-032-2
GENCLS, gencls	Classical Generator Model (IEEE Std 1110 §5.4.2)	Effective Date of MOD-032-2
GENTRA	Transient Level Generator Model	Effective Date of MOD-032-2
Excitation System Models		
texs	General Purpose Transformer Fed Excitation System	Effective Date of MOD-032-2
SEXS, sexs	Simplified Excitation System	Effective Date of MOD-032-2
EX2000	GE EX2000 Excitation System	Effective Date of MOD-032-2
Turbine-Governor Models		
lm2500	LM 2500 Aero-Derivative Gas Turbine Governor Model	Effective Date of MOD-032-2
Known Unacceptable Model Name	**Model Description**	**Effective**

Table 1: Unacceptable Model List		
lm6000	LM 6000 Aero-Derivative Gas Turbine Governor Model	Effective Date of MOD-032-2
URGS3T, gast	WECC Gas Turbine Governor Model	Effective Date of MOD-032-2
GAST	Gas Turbine-Governor Model	Effective Date of MOD-032-2
GAST2A	Gas Turbine-Governor Model	Effective Date of MOD-032-2
GASTWD	Gas turbine-governor	Effective Date of MOD-032-2
IEEEG2	1981 IEEE Type 2 General Approx. Linear Ideal Hydro Model	Effective Date of MOD-032-2
WESGOV	Westinghouse Digital Governor Model for Gas Turbines	Effective Date of MOD-032-2
Load Models		
motorc	Phasor Model of Single-Phase Air-Conditioner Compressor Motor	Effective Date of MOD-032-2

Chapter 2: Unacceptable Models Technical Rationale

Table 2 below provides the technical rationale for each unacceptable model included on the current Unacceptable Models List.

The purpose of this list of unacceptable models is to develop and maintain a repository of models deemed acceptable by the ERO and industry stakeholders for use in developing interconnection-wide models developed by the MOD-032 Designee. The NERC System Analysis and Modeling Subcommittee (SAMS) initially developed this list, and it is now maintained and updated by ERO staff in accordance with MOD-032 Supporting Document. This list seeks to bring together multiple sources of data to ensure uniformity in the use of models across Interconnections. While models may be deemed 'obsolete' or 'deprecated' due to known issues, these models are not removed from the software vendor libraries for various reasons. However, these models should not be used to represent specific facilities within Interconnection-wide models. For additional information about this list, please contact NERC staff at advancedsystemanalyticsmodeling@nerc.net with any questions.

Table 2: Unacceptable Model List

Known Unacceptable Model Name	Rationale For Inclusion
Renewable Energy Models	
WT3G1, WT3G2, wt3g	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT4G1, WT4G2, wt4g	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3E1, wt3e	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT4E1, WT4E2, wt4e	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3T1, wt3t	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3P1, wt3p	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT12A1, wt1p, wt2p	Unable to represent common Type 1 wind pitch control logic.
WT4E1, wt4t	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
wt4p	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
REECB1, REECBU1, reec_b	Inability to represent momentary cessation or other voltage dependent current logic common in the equipment the model was stated to represent.
Machine Models	

Table 2: Unacceptable Model List	
Known Unacceptable Model Name	**Rationale For Inclusion**
GENSAL, gensal	Uses simplifying approximations for saturation as additive terms over exponential or quadratic curves. Further, ignores the q-axis saturation completely.
GENCLS, gencls	Does not allow for representation of excitation system and turbine/speed governor models
GENTRA	Simplified model that ignores sub transient effects, leading to numerical instability problems.
Excitation System Models	
texs	Simplified, early generation model considered obsolete. Refer to IEEE Std 421.5
SEXS, sexs	Simplified, early generation model considered obsolete. Refer to IEEE Std 421.5
EX2000	Field current limiter latch in the model is unable to represent the field equipment for simulation in power system software. Replace with AC7B or ex21br
Turbine-Governor Models	
lm2500	No supporting documentation implemented in software, proprietary model with no added model support.
lm6000	No supporting documentation implemented in software, proprietary model with no added model support.
URGS3T, gast	Simple representation of steam turbine-governor system with insufficient model capability for modern digital controllers.
GAST	Simple representation of steam turbine-governor system with insufficient model capability for modern digital controllers.
GAST2A	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
GASTWD	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
IEEEG2	Model uses an oversimplified governor model applicable only to first swing stability. Deprecated with other hydro governor models.
WESGOV	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
Load Models	
motorc	Experimental load model. Should not be used for generation resources

Additional References

The references below are provided for further reading and information about the models above. These references are:

- "IEEE Guide for Synchronous Generator Modeling Practices and Applications in Power System Stability Analyses," IEEE Std 1110-2002.
- Undrill, J., "The gentpj model," November 19, 2007 (updated June 19, 2012).
- "IEEE Recommended Practice for Excitation System Models for Power System Stability Studies," IEEE Std 421.5-2005.
- "Computer Representation of Excitation Systems," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-87, No. 6, pp. 1460-1468, 1968 (Committee Report).
- "Excitation System Models for Power System Stability Studies," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 2, pp. 494-509, 1981 (Committee Report).

- IEEE Task Force on Overall Plant Response, "Dynamic Models for Steam and Hydro Turbines in Power System Studies", IEEE Trans. on PAS, Vol PAS-92, Nov-Dec 1973, pp. 1904-1915.
- Task Force on Turbine-Governor Modeling, "Dynamic Models for Turbine-Governors in Power System Studies," IEEE Technical Report, PES-TR1, Jan. 2013.
- WECC M&VWG, "Composite Load Model for Dynamic Simulations" Ver 1.0, June 12, 2012.
- WECC M&VWG, "WECC Wind Power Plant Dynamic Modeling Guide," November 2010.
- EPRI, "Specification of the Second Generation Generic Models for Wind Turbine Generators," September 20, 2013. and WECC M&VWG, "Generic Solar Photovoltaic System Dynamic Simulation Model Specification," September 2012.
- WECC, "Generic Static Var System Models for the Western Electricity Coordinating Council" April 18, 2011.
- W. I. Rowen, "Simplified Mathematical Representations of Heavy Duty Gas Turbines", ASME Paper 83-GT-63 and ASME Journal of Engineering for Power, October 1983, pages 865-869. [GAST2A reference]
- Periera, L. et al, "A New Thermal Governing Approach in the WECC," IEEE Transaction on Power System, Vol. 18, No. 2, pp. 819-829, May 2003.
- WECC M&VWG, "Cross-current Compensation Model Specification," August 2015.
- EPRI, "Simple Model Specification for Battery Energy Storage System," March 6, 2015.
- WECC M&VWG, "WECC Wind Power Plant Dynamic Modeling Guide," April 2014.
- WECC M&VWG, "WECC PV Power Plant Dynamic Modeling Guide," April 2014.
- EPRI, "Proposed Changes to the WECC WT3 Generic Model for Type 3 Wind Turbine Generators," September 27, 2013.
- EPRI, "Proposed Changes to the WECC WT4 Generic Model for Type 4 Wind Turbine Generators," January 23, 2013.
- Q. Wang, "GENQEC Generator Dynamic Model", July, 2019. https://www.wecc.org/Administrative/GENQEC%20Model%20Specification.pdf
- Q.Y. Wang, S. Wang, "A New High Accuracy Generator Dynamic Model", 2018 IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC).

Chapter 3: Sample Submission Form

This form is a sample to explain what is deemed a full application to change a model designation in the Unacceptable Models List.

Section 1: Submitting Entity Information			
Name of Person submitting			
Organization(s)			
Sector (if known)			
Telephone		Email	

Section 2: Model Identifying Information	
Model Name	
Alternative Model Name(s) as implemented in software	
Equipment Model is stated to represent	
Indicate desired Action	☐ Add model to the Unacceptable Models List ☐ Remove model from the Unacceptable Models List

Section 3: Technical Supporting Documentation and Description	
Description of model ability to meet small signal Disturbances	
Description of model ability to meet large signal Disturbances	
Please cite and link any industry approved documentation regarding this model's small and large signal disturbances	
Describe the technical document attachments that support the above questions	
Please identify any information in this application that may meet the criteria for Confidential Information, as defined in Section 1500 of the NERC Rules of Procedure	

Section 4: Process Tracking	
Date Submitted to ERO	
Model Status	☐ Submitted to the ERO ☐ Assigned ERO Review team ☐ Investigation and review by ERO and submitting entity ☐ Remanded by NERC RSTC (or its successor) ☐ Approved by the NERC RSTC (or its successor)
Date of Approval	
Date of Model Notice to Industry	

Attachments

If available, please include at least one report that uses Hardware-in-the-Loop, Software-in-the-Loop, or actual System response (e.g., in a commissioning test) to demonstrate the model's ability or inability to achieve its stated purpose. At least one attachment should detail the model's error boundaries to represent its stated equipment with the test description and procedure outlined in that report. Entities shall label any attachment that may meet the criteria for Confidential Information under NERC Rules of Procedure Section 1500, along with the basis for the designation (e.g., Confidential Business and Market Information, Critical Electric Infrastructure Information, etc.). If any of this information is not available to the supporting entity, please provide an explanation.

Chapter 4: Version History

Version	Date	Action	Change Tracking
1	August 2025	Draft 2 Posting for Project 2022-02	Initial Draft

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Exhibit G

Analysis of Violation Risk Factors and Violation Severity Levels

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Violation Risk Factor and Violation Severity Level Justifications

Project 2022-02 Uniform Modeling Framework for IBR

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-02 Uniform Modeling Framework for Inverter-Based Resources (IBRs). 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 the Federal Energy Regulatory Commission (FERC)-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The drafting team applied the following North American Electric Reliability Corporation (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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R1 require model submission in accordance with the Criteria for Acceptable Models maintained by the ERO. This is similar to other sub-requirements in Requirements R1; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R1

Please refer to the VSL table below.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. “Load Serving Entity” was replaced with “Distribution Provider” from Requirement R2 in MOD-032-2. In addition, Requirement R2 added a sub-requirement requiring if entity is unable to gather unregistered IBR data or Distributed Energy Resource (DER) data to complete an estimate. These modifications align with the medium risk requirement and therefore, the VRF remained medium.

VSL Justification for MOD-032-2, Requirement R2

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R3 were administrative in nature; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R3

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSLs for MOD-032-1, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

VSL Justifications for MOD-032-1, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional sub-requirement to Requirement R1. The proposed VSL was modified to reflect the additional sub-requirement. It does not have an 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 updated sub-requirement requires the responsible entity to follow the Criteria for Acceptable Models document maintained by the Electric Reliability Organization. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner,

of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.

VSL Justifications for MOD-032-1, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 and a sub-requirement was added requiring if entity is unable to gather unregistered IBR data or DER data to complete an estimate. The proposed VSL was modified to reflect the additional sub-requirement language. It does not have an 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 updated sub-requirement requires the entity if it is unable to gather unregistered IBR data or DER data to complete an estimate. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 3			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

VSL Justifications for MOD-032-1, Requirement 3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by replacing Load Serving Entity with Distribution provider. The proposed VSL was modified to reflect this modification. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

IRO-010-5

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for IRO-010-5, Requirement R1

Please refer to the VSL table located below.

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R2

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VRF Justification for IRO-010-5, Requirement R3

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R3

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSLs for IRO-010-5, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

VSL Justifications for IRO-010-5, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

TOP-003-8

VRF Justification for TOP-003-8, Requirement R1

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R1

Please refer to the VSL table located below.

VRF Justification for TOP-003-8, Requirement R2

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R2

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R3

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R3

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R4

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R4

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R5

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R5

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSLs for TOP-003-8, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

VSL Justifications for TOP-003-8, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for TOP-003-8, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-8, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R2. The proposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

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Exhibit H

Summary of Development History
and Complete Record of Development

Summary of Development History

The following is a summary of the development record for the proposed Reliability Standards MOD-032-2, IRO-010-6, and TOP-003-8, developed through Project 2022-02 Uniform Modeling Framework for IBR (Phase One).

I. Overview of the Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2022-02 drafting team members is included in **Exhibit I**.

II. Standard Development History

A. Standard Authorization Request Development – 2021/2022

The NERC Standards Committee ("SC") established Project 2022-02 in response to three Standard Authorization Requests ("SARs") submitted in December 2021 regarding impacts of Distributed Energy Resources and Inverter-Based Resources ("IBRs") on the Bulk-Power System. First, the NERC System Performance Impacts of Distributed Energy Resources Working Group ("SPIDERWG") submitted two SARs: one sought revisions to MOD-032 to address gaps in data collection for the purposes of modeling aggregate levels of distributed energy resources in planning assessments; the second sought revisions to TPL-001 to consider the impacts of these resources in planning assessments. A third SAR was submitted by the NERC Inverter-Based

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

[2] The NERC *Standard Processes Manual* is available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

Resource Performance Task Force ("IRPTF") seeking to revise TPL-001 to provide clarity and consistency for how BPS-connected IBRs are considered, modeled, and studied in transmission planning assessments.

At its January 19, 2022 meeting, the SC accepted the SARs, which were endorsed by the Reliability, Security, and Technology Committee, and authorized posting all three for a 30-day informal comment period, as well as authorized solicitation of drafting team ("DT") members.[3] The SARs and DT nominations were posted from February 1, 2022 – March 2, 2022. NERC received 39 sets of responses, including comments from approximately 126 different people from approximately 88 companies representing all 10 of the Industry Segments.[4]

At its April 20, 2022 meeting, the SC appointed members to the Project 2022-02 SARs drafting team.[5] The SARs DT considered industry comments and revised the SARs. The SC accepted the revised SARs at its September 21, 2022 meeting; authorized drafting revisions to the Reliability Standards identified in the SARs; and appointed the Project 2022-02 SARs Drafting Team as the Project 2022-02 Standard Drafting Team ("SDT").[6]

B. First Posting – Comment Period and Initial Ballot under Original Project Scope

At its May 17, 2023 meeting, the SC authorized posting of draft one of proposed Reliability Standard MOD-032-2 and the associated Implementation Plan for a 45-day formal comment period, with ballot pools formed in the first 30 days, and parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), conducted

[3] NERC Standards Committee Meeting Minutes (Jan. 19, 2022), Transmission System Planning and Modeling Improvements (Agenda Item 9).
[4] Exhibit H Item 6.
[5] NERC Standards Committee Meeting Minutes (Apr. 20, 2022), Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 (agenda item 8).
[6] NERC Standards Committee Meeting Minutes (Sept. 21, 2022), Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 (agenda item 8).

during the last 10 days of the comment period.[7] The initial posting took place from May 31, 2023 – July 14, 2023, with an initial ballot taking place over the last 10 days.

There were 77 sets of responses, including comments from approximately 200 different people from approximately 126 companies representing 10 of the Industry Segments.[8]

Results for the initial ballot and non-binding poll are in the table below:[9]

Standard	Approval	Quorum	Non-binding Poll / Quorum
MOD-032-2	41.82%	84.54%	39.78% / 82.31%
Implementation Plan	41.48%	82.7%	N/A

C. Second Posting – Comment Period and Additional Ballot under Original Project Scope

After reviewing the comments received, the SDT revised proposed Reliability Standard MOD-032-2 and posted draft two of the standard and the associated Implementation Plan for a 45-day formal comment period and an additional ballot and non-binding poll. The posting took place from October 6, 2023 – November 20, 2023, with an additional ballot taking place over the last 10 days.

NERC received 71 sets of responses, including comments from approximately 185 different people from approximately 114 companies representing 10 of the Industry Segments.[10]

Results for the additional ballot and non-binding poll are in the table below:[11]

Standard	Approval	Quorum	Non-binding Poll / Quorum
MOD-032-2	39.52%	85.27%	41.24% / 83.09%
Implementation Plan	48.24%	84.83%	N/A

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7 NERC Standards Committee Meeting Minutes (May 17, 2023), Modifications to CIP-002-5.1a – Criterion 1.3 Revision (agenda item 5), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/May%20Meeting%20Minutes%20-%20Approved%20June%2021,%202023.pdf.

8 Exhibit H Item 23.

9 Exhibit H Items 27-29.

10 Exhibit H Item 41.

11 Exhibit H Items 45-47.

D. Order No. 901

While work was underway to revise Reliability Standard MOD-032-1 to account for distributed energy resources, the Commission issued Order No. 901 directing NERC to submit a series of proposed new or revised Reliability Standards to address IBR-related reliability issues, including data and modeling issues.[12]

Specifically, Order No. 901 included several directives related to IBR modelling and data sharing requirements. Project 2022-02 was assigned these directives, with the goal to establish new or revised Reliability Standards to ensure the usage of a uniform framework for data sharing and model development. The Order No. 901 directives would be addressed as Phase One of the project, and other remaining work from the original three SARs not addressed with the Order No. 901 directives would be assigned to Phase Two.

E. SAR for Addressing Order No. 901 Directives and Supplemental Drafting Team Nominations

NERC staff drafted a SAR addressing relevant directives from FERC Order No. 901 and renaming project 2022-02 to Uniform Modeling Framework for IBR. The SAR was posted for comment from May 17, 2024 – June 24, 2024. There were 34 sets of responses, including comments from approximately 113 different people from approximately 80 companies representing all 10 of the Industry Segments.[13]

Concurrently, supplemental drafting team nominations were posted from May 17, 2024 – June 24, 2024. The posting highlighted the high priority nature of the project and the need to meet

[12] Order No. 901, *Reliability Standards to Address Inverter-Based Resources*, 185 FERC ¶ 61,042 (2023).
[13] Exhibit H Item 53.

the November 4, 2025 FERC directive deadline. The SC appointed members to the Project 2022-02 SAR DT at its August 21, 2024 meeting.[14]

F. Third Posting – Comment Period and Additional Ballot under Original Project Scope

A third draft of proposed Reliability Standard MOD-032-2 (not considering the Order No. 901 directives) and the associated Implementation Plan were posted for 45-day formal comment period from August 27, 2024 – October 10, 2024, with an additional ballot conducted during the last 10 days of the comment period.

There were 55 sets of responses, including comments from approximately 140 different people from approximately 87 companies representing 7 of the Industry Segments.[15]

Results for the additional ballot and non-binding poll are in the table below:[16]

Standard	Approval	Quorum	Non-binding Poll / Quorum
MOD-032-2	41.9%	84.93%	41.57% / 82.01%
Implementation Plan	45.81%	83.79%	N/A

G. Revised SAR Addressing Order No. 901 Directives Accepted

As work continued on MOD-032-2, the project 2022-02 DT revised the SAR addressing directives from Order No. 901. The Standards Committee accepted the SAR on November 13, 2024 and authorized drafting revisions to the Reliability Standards.[17]

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[14] NERC Standards Committee Meeting Minutes (Aug. 21, 2024), Project 2022-02 Uniform Modeling Framework for IBR (agenda item 5), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Meeting_Minutes-August_2024.pdf.

[15] Exhibit H Item 65.

[16] Exhibit H Items 68-70.

[17] NERC Standards Committee Meeting Minutes (Nov. 13, 2024), Project 2022-02 Uniform Modeling Framework for IBR (agenda item 6), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Meeting_Minutes%20-%20November_13_2024.pdf.

H. Waiver

At its April 16, 2025 meeting, the SC considered a waiver of certain provisions of the Standard Processes Manual relating to the lengths of comment periods and ballots in order to meet the Order No. 901 November 4, 2025 filing deadline. The Standards Committee approved the waiver on April 16, 2025.[18]

I. Phase One – Initial Comment Period and Initial Ballot for Standards Responsive to Order No. 901 Directives

After completing the SAR addressing Order No. 901 directives and splitting Project 2022-02 into two phases, work continued on Phase One of the project. The posting and ballot process was restarted.

Draft 1 of proposed Reliability Standards MOD-032-2, IRO-010-6, TOP-003-8 and the associated Implementation Plan were posted from April 17, 2025 – May 16, 2025 for an initial 30 day formal comment and ballot period, with ballot pools formed in the first 10 calendar days, and initial ballots conducted during the last 10 calendar days of the comment period.

There were 82 sets of responses, including comments from approximately 174 different people from approximately 105 companies representing 8 of the Industry Segments.[19]

Results for the initial ballots and non-binding polls are in the table below:[20]

Standard	Approval	Quorum	Non-binding Poll / Quorum
MOD-032-2	39.05%	87.86%	39.6% / 88.46%
IRO-010-6	41.62%	87.54%	87.36% / 49.74%
TOP-003-8	34.7%	87.9%	87.69% / 41.75%
Implementation Plan	39.46%	88%	N/A

[18] Exhibit H item 73 (Waiver) and 74 (NERC standards Committee Meeting Minutes (Apr. 16, 2025), Project 2022-02 Uniform Modeling Framework for IBR (agenda item 5)).

[19] Exhibit H Item 88.

[20] Exhibit H Items 92-98.

J. Phase One – Additional Comment Period and Additional Ballot

A revised draft of proposed Reliability Standards MOD-032-2, IRO-010-5, TOP-003-8 and the associated Implementation Plan for a 30-day formal comment period, with an additional ballot conducted during the last 10 days of the comment period. The posting took place from August 8, 2025 – September 10, 2025, with an additional ballot taking place over the last 10 days.

There were 71 sets of responses, including comments from approximately 185 different people from approximately 114 companies representing 10 of the Industry Segments.[21]

Results for the additional ballots and non-binding polls are in the table below:[22]

Standard	Approval	Quorum	Non-binding Poll / Quorum
MOD-032-2	73.77%	91.79%	71.94% / 91.15%
IRO-010-6	86.15%	91.1%	93.26% / 90.42%
TOP-003-8	82.56%	91.46%	91.53% / 90.38%
Implementation Plan	76.84%	91.27%	N/A

K. Final Ballot

The proposed Reliability Standards, implementation plan, and supporting materials were posted for a five-day final ballot from September 29, 2025 – October 3, 2025. All items reached quorum and passed the ballot as indicated in the table below:[23]

Ballot	Quorum / Approval
MOD-032-2	93.21% / 78.73%
IRO-010-6	92.53% / 87.78%
TOP-003-8	92.88% / 84.3%
Implementation Plan	92.73% / 79.39%

[21] Exhibit H Item 116.
[22] Exhibit H Items 120-126.
[23] Exhibit H Items 143-146.

L. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standards MOD-32-2, IRO-010-6, and TOP-003-8, as well as the implementation plan on October 31, 2025.[24]

[24] NERC, Board of Trustees Action without a Meeting (Oct. 31, 2025), available at https://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx.

Complete Record of Development

Project 2022-02 Uniform Modeling Framework for IBR

Related Files

Status
Final ballots for **Project 2022-02 Uniform Modeling Framework for IBR** concluded at **8 p.m. Eastern, Friday, October 3, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- Implementation Plan

The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Project 2022-02 Uniform Modeling Framework for IBR has been assigned a new standard authorization request (SAR) addressing FERC Order 901 and has 24 regulatory directives. This project has been split into two phases. Phase one will address FERC Order 901, which has a regulatory deadline of November 4, 2025. Phase two will commence once phase one has been completed.

Background for Phase One
Project 2022-02 Uniform Modeling Framework for IBR will address 24 regulatory directives from FERC Order No. 901 – Milestone 3, Phase one. Specifically, modeling and data sharing requirements to establish sufficient IBR model data and parameters to assure accurate representation of IBR performance within the models. This project is intended to establish new or revised Reliability Standards to ensure the usage of a uniform framework for data sharing and model development. This uniform framework is to ensure the directives of Order No. 901 can be effectively met to ensure usage of generic model types for IBR in the Interconnection-wide models.

This project must ensure modeling revisions from other IBR performance requirements in other 901-related projects will utilize the uniform framework. For instance, performance of IBR during an event (grid disturbance) is identified and corrected within Milestone 2 of FERC Order No. 901. Evaluated performance within new PRC-029 or PRC-030 may necessitate some form of change to how specific IBRs are represented in the model; as the IBR should be modeled based on how it performs during a disturbance and/or new/changed equipment as a result of failing to ride through. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). This project, Milestone 3 Phase one, will establish the uniform framework for data sharing and model development of future Order No. 901 related projects that will utilize performance data.

This project has been identified as high priority at this time. The project has a FERC deadline of November 4, 2025.

Standard(s) Affected for Phase One: MOD-032, IRO-010, and TOP-003

Background for Phase Two
Due to the priority of FERC Order 901 directives, the TPL-001 SARs will be addressed during Phase two for Project 2022-02 and is not expected to be a high priority project. While the current DT of Project 2022-02 is working on the project, a new SAR related to TPL-001-5.1 was approved for posting by the Standards Committee. The Standards Committee asked the current DT to include this SAR as part of the project rather than creating a new project. The new SAR will address Footnote 13d issue in Standard TPL-001-5.1. Please see the TPL-001 SAR for additional information.

Standard(s) Affected for Phase Two: TPL-001-5.1 and MOD-032-1

Purpose/Industry Need

Phase One
Phase one will provide industry with a uniform framework for each Interconnection that includes a minimum modeling criteria consistent with NERC's Dynamic Modeling Recommendations, a registered modeling designee, and necessary data exchange requirements.

Phase Two
Phase two will provide clarity, or in some cases, expand the scope of requirements when considering the performance of DERs to ensure the accuracy of Transmission System Planning Assessments.

Subscribe to this project's observer mailing list
Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR" in the Title and Description Boxes.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **MOD-032-2** Clean **(127)** | Redline to Last Posted **(128)**| Redline to Last Approved **(129)** **IRO-010-6**	Final Ballot Info **(142)** Vote	09/29/25 – 10/03/25	**Ballot Results** MOD-032-2 **(143)** IRO-010-6 **(144)** TOP-003-8 **(145)**	

Clean **(130)** | Redline to Last Posted **(131)** | Redline to Last Approved **(132)** **TOP-003-8** Clean **(133)**| Redline to Last Posted **(134)**| Redline to Last Approved **(135)** **Implementation Plan (136)** **Supporting Materials** VRF/VSL Justifications **(137)** Technical Rationale **(138)** **Consideration of FERC Directives** Clean **(139)**| Redline to Last Posted **(140)** ERO Unacceptable Models List **(141)**			Implementation Plan **(146)**	
Draft 2 **MOD-032-2** Clean **(99)**| Redline to Last Posted **(100)**| Redline to Last Approved **(101)** **IRO-010-6** Clean **(102)** | Redline to Last Posted **(103)** | Redline to Last Approved **(104)** **TOP-003-8** Clean **(105)** | Redline to Last Posted **(106)** | Redline to Last Approved **(107)** **Implementation Plan** Clean **(108)** | Redline **(109)** **Supporting Materials** Unofficial Comment Form (Word) **(110)** VRF/VSL Justification **(111)** Technical Rationale **(112)** Consideration of FERC Directives **(113)** ERO Approved Criteria for Acceptable Models **(114)**	Additional Ballots and Non-binding Polls Ballots Open Reminder **(118)** 08/28/25 – 09/10/25 Info **(119)** Vote Comment Period Info **(115)** 08/08/25 – 09/10/25 Submit Comments		**Ballot Results** MOD-032-2 **(120)** IRO-010-6 **(121)** TOP-003-8 **(122)** Implementation Plan **(123)** **Non-Binding Poll Results** MOD-032-2 **(124)** IRO-010-6 **(125)** TOP-003-8 **(126)** Comments Received **(116)**	Consideration of Comments **(117)**
Draft 1 **MOD-032-2** Clean **(75)** | Redline **(76)** **IRO-010-6** Clean **(77)** | Redline **(78)** **TOP-003-8** Clean **(79)** | Redline **(80)** Implementation Plan **(81)** **Supporting Materials** Unofficial Comment Form (Word) **(82)** VRF/VSL Justification **(83)** Technical Rationale **(84)** Consideration of FERC Directives **(85)** ERO Approved Criteria for Acceptable Models **(86)** **Waiver** Waiver **(73)** | Meeting Minutes **(74)**	Initial Ballots and Non-binding Polls Ballots Open Reminder **(90)** 05/07/25 – 05/16/25 Info **(91)** Vote Join Ballot Pools 04/17/25 – 04/28/25 Comment Period Info **(87)** Submit Comments The Standards Committee accepted the waiver on April 16, 2025	04/17/25 – 05/16/25	**Ballot Results** MOD-032-2 **(92)** IRO-010-6 **(93)** TOP-003-8 **(94)** Implementation Plan **(95)** **Non-Binding Poll Results** MOD-032-2 **(96)** IRO-010-6 **(97)** TOP-003-8 **(98)** Comments Received **(88)**	Consideration of Comments **(89)**
FERC Order No. 901, Milestone 3, Part 1 SAR Clean **(71)** | Redline **(72)**	The Standards Committee accepted this SAR on November 13, 2024			

Draft 3 **MOD-032-2** Clean **(54)** | Redline to Last Posted **(55)** | Redline to Last Approved **(56)** **This posting affects Phase I of the project for proposed Reliability Standard MOD-032-2 and does not contemplate the SAR related to FERC Order No. 901; the Milestone 3, Part 1** **Implementation Plan** Clean **(57)** | Redline **(58)** **Supporting Materials** Unofficial Comment Form (Word) **(59)** **VRF/VSL Justification** Clean **(60)** | Redline **(61)** **Technical Rationale** Clean **(62)** | Redline **(63)**	Additional Ballots and Non-binding Polls Ballots Open Reminder **(66)** Info **(67)** Vote	10/01/24– 10/10/24	**Ballot Results** MOD-032-2 **(68)** Implementation Plan **(69)** **Non-Binding Poll Results** MOD-032-2 **(70)**	
	Comment Period Info **(64)** Submit Comments	08/27/24– 10/10/24	Comments Received **(65)**	
FERC Order No. 901, Milestone 3, Part 1 SAR (50) **Additional Materials** Unofficial Comment Form (Word) **(51)**	Comment Period Info **(52)** Submit Comments	05/17/24 - 06/24/24	Comments Received **(53)**	
Supplemental Drafting Team Nominations **Additional Materials** Unofficial Nomination Form (Word) **(48)**	Nomination Period Info **(49)** Submit Nominations	05/17/24 - 06/24/24		
Draft 2 **MOD-032-1 (For reference only) (30)** **MOD-032-2** Clean **(31)**| Redline to Last Posted **(32)**| Redline to Last Approved (updated) **(33)** **Implementation Plan** Clean **(34)**| Redline to Last Posted **(35)** **Supporting Materials** Unofficial Comment Form (Word) **(36)** VRF/VSL Justification **(37)** **Technical Rationale** Clean **(38)**| Redline to Last Posted **(39)**	Additional Ballots and Non-binding Polls Ballots Open Reminder **(43)** Info **(44)** Vote	11/10/23 – 11/20/23	**Ballot Results** MOD-032-2 **(45)** Implementation Plan **(46)** **Non-Binding Poll Results** MOD-032-2 **(47)**	
	Comment Period Info **(40)** Submit Comments	10/06/23 – 11/20/23	Comments Received **(41)**	Consideration of Comments **(42)**
Draft 1 **MOD-032-1 (For reference only) (15)** **MOD-032-2** Clean **(16)** | Redline **(17)** Implementation Plan **(18)**	Initial Ballots and Non-binding Polls Ballots Open Reminder **(25)** Info **(26)** Vote	07/05/23 – 07/14/23	**Ballot Results** MOD-032-2 **(27)** Implementation Plan **(28)** **Non-Binding Poll Results** MOD-032-2 **(29)**	
Supporting Materials Unofficial Comment Form (Word) **(19)** VRF/VSL Justification **(20)** Technical Rationale **(21)**	Join Ballot Pools	05/31/23 – 06/29/23		
	Comment Period Info **(22)** Submit Comments	05/31/23 – 07/14/23	Comments Received **(23)**	Consideration of Comments **(24)**
TPL-001-5.1 Footnote 13.d SAR (Phase Two) **Supporting Materials** Unofficial Comment Form (Word)	Comment Period Info Submit Comments	04/13/23 – 05/12/23	Comments Received	
TPL-001-5.1 IRPWG SAR Clean **(9)** | Redline **(10)**				

TPL-001-5.1 SPIDERWG SAR Clean **(11)** | Redline **(12)** **MOD-032-1 SAR** Clean **(13)** | Redline **(14)**	The Standards Committee accepted these SARs on September 21, 2022			
Drafting Team Nominations Supporting Materials Unofficial Nomination Form (Word) **(7)**	Nomination Period Info **(8)** Submit Nominations	02/01/22 – 03/02/22		
TPL-001-5.1 IRPWG SAR (1) **TPL-001-5.1 SPIDERWG SAR (2)** **MOD-032-1 SAR (3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	02/01/22 – 03/02/22	Comments Received **(6)**	

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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:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/16/2021		
SAR Requester			
Name:	Allen Schriver, NextEra Energy (NERC IRPWG Chair) Julia Matevosyan, ERCOT (NERC IRPWG Vice Chair)		
Organization:	NERC Inverter-Based Resource Performance Working Group (IRPWG)		
Telephone:	Al – 561-904-3234 Julia – 512-994-7914	Email:	Allen.Schriver@fpl.com Julia.Matevosyan@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?):			
Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward.			

Requested information
The NERC Inverter-Based Resource Performance Task Force (IRPTF)[1] undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020.[2] The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. The white paper recommended modifications to seven standards, and IRPWG presented four SARs to the NERC Reliability and Security Technical Committee (RSTC) in June 2020 that addressed the deficiencies identified in six of the seven standards. Based on the outcome of the review, it was determined that the TPL-001-4/5[3] needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The language used in the white paper regarding "the next time the standard is revised" was based on the understanding that the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was developing a SAR and that the recommended modifications to TPL-001-5 from IRPWG could be included in the SPIDERWG SAR. The combined SAR was presented to the NERC RSTC at their March 2021 meeting and was rejected. The overarching comments received were with regards to the DER-related issues and a comment was made that the recommendations pertaining to BPS-connected inverter-based resources were not the primary focus of concern. Therefore, IRPWG presents this SAR to move the effort forward regarding specifically BPS-connected inverter-based resources. This SAR does not include any modification to TPL-001-5 regarding the inclusion of distributed energy resources (DERs). IRPWG believes that industry needs to be proactive in addressing standards gaps, particularly, where lack of clarity and confusion may lead to studies not adequately capturing possible BPS reliability issues. As the North American BPS continues to experience rising penetration levels of BPS-connected inverter-based resources and is likely to do so into the foreseeable future, these changes are critical for overall BPS reliability and industry efforts to reliably integrate these resources.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR revises requirements within the TPL-001-5 standard to provide clarity and consistency for how BPS-connected inverter-based resources are considered, modeled, and studied in planning assessments. The proposed revisions to TPL-001-5 will ensure industry is effectively and efficiently conducting planning assessments and that the requirements are equally suitable for inverter-based resources as they are for synchronous generation.

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).
[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf
[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

Requested information
Project Scope (Define the parameters of the proposed project):
As described in further detail below, the scope of this project includes the following revisions to TPL-001-5.1: • Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term "GSU transformer" suitable for all generation types since it introduces confusion for BPS-connected inverter-based resources • Modify Requirements 4.1.1 and 4.1.2 regarding the use of the term "pulls out of synchronism," which is only applicable for synchronous generator technologies and is not suitable for BPS-connected inverter-based resources • Modify Requirement 4.3.2 so that the list of devices that impact the study area are inclusive of BPS-connected inverter-based resource technologies •
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The following detailed description is copied verbatim from the IRPTF white paper that was approved by the NERC PC: 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 main power transformer (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

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

Requested information
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.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impacts for the proposed changes to TPL-001-5 are expected to be minimal. The changes being proposed are clarifications that will bring consistency and effectiveness industry related to how planning assessments are conducted and how planning engineers set up and conduct those assessments.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will impact Transmission System Planning Assessments, not any specific BES facilities.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinators, Transmission Planners, and Generator Owners of inverter-based resources

Requested information
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.
This SAR is an outcome of the white paper produced by the NERC IRPTF and approved by the NERC PC, which can be found here: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf The SAR is a follow-on to the recommendation contained within the white paper, developed by the NERC IRPWG under the NERC RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
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 NERC IRPWG (previously IRPTF) has published multiple technical reference documents, white papers, and reliability guidelines related to the performance, modeling, and studies of BPS-connected inverter-based resources. These technical materials are used widely by industry and have provided significant value for improving planning practices. However, those efforts do not address the larger issue related to the TPL-001 standards language being written predominantly for synchronous generation technology and not adequately considering or clarifying how the requirements relate to BPS-connected inverter-based resource technologies.

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.

[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	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

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

For Use by NERC Only

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

Version History

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

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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:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/15/2021		
SAR Requester			
Name:	Kun Zhu, MISO (NERC SPIDERWG Chair) Bill Quaintance, Duke Energy Progress (NERC SPIDERWG Vice-Chair)		
Organization:	NERC System Planning Impacts from DERs Working Group (SPIDERWG)		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.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?):			
Many areas of the North American BES are experiencing increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-5.1[1] was developed under a paradigm of predominantly BPS-connected generation, particularly synchronous generation, when penetrations of DERs were significantly lower than current and future projections. Considering current trends, the NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR: • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here)			

[1] The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BPS planning.

Requested information

This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper.

TPL-001-5.1 does not currently require Planning Coordinators and Transmission Planners to complete Planning Assessments with adequate representation of the dynamic behavior of DERs. As the penetration of DERs increases, and based on the DER data and models available, Planning Assessments should include DERs that can potentially impact Transmission System performance assessment. NERC's "Lesson Learned: Single Phase Fault Precipitates Loss of Generation and Load", evaluating a 2019 frequency event in Southern England exacerbated by the unexpected reduction of 725 MW of IBR output and the unexpected loss of 350 MW of DER, highlights the critical importance of accurate Transmission System Planning Assessments.[2] In July 2020, a significant quantity of solar PV facilities across a large geographic area in Southern CA reduced about 1000 MW output due to a disturbance on the bulk power system[3]. Subsequent event analysis revealed that it was the consequence of momentary cessation and slow recovery of power. Standards enhancement has been one of the recommendations after the event analysis to ensure reliable operation of the bulk power system.

In general, the impact of DERs on the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or justification.

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

The purpose of this SAR is to revise requirements to provide clarity or, in some cases, expand the scope of requirements when considering the performance of DERs to ensure the accuracy of Transmission System Planning Assessments.

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

As identified by SPIDERWG, the following sections of TPL-001-5.1 should be revised to ensure the accuracy of Transmission System Planning Assessments:

a. R2.1 and R2.2, the use of phrase "System peak Load"
b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data and models are available. The SDT can consider whether a threshold needs to be established.
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER.

[2] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201001_Single_Phase_Fault_Precipitates_Loss_of_Generation_and_Load.pdf

[3] https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

Requested information
d. R4.3.2, the list of dynamic control devices should include DER so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
A detailed description of each Project Scope item is given below: a. R2.1 and R2.2, the use of phrase "System peak Load" With increased penetration of DER, the load that transmission system supplies is the net load (net load = gross load – DER output) as seen at the T-D interface, which might reach its peak during operating conditions that are not at the peak gross load hour. As such, there is a need for individual TPs to be required to document and define their peak load conditions (e.g., gross or net) in their assessments. The SDT should consider adding the terms "Gross Load" and "Net Load" to the NERC Glossary of Terms and updating the term "System peak Load" in the standard to "System peak net Load". In addition, a high gross load hour may be the most stressed load driven condition for contingencies that may trip large amounts of DER. High system peak gross load may be studied as additional scenarios as required by current standard under R2.1.3. b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data is available. The SDT can consider whether a threshold needs to be established. The terms "generators" in Sub-requirements 3.3.1.1 and 4.3.1.2 should be clarified. DERs that are explicitly modeled as generators should be tripped where simulations show bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to consider inclusion in the assessment any assumptions made in estimating DER bus voltage. c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. For example, the language referring to "pulls out of synchronism" is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). However, large amounts of asynchronous DER tripping on low/high voltage/frequency conditions

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

Requested information
can also adversely affect BES performance and may pose a risk to system instability for conditions such as cascading, voltage instability, or uncontrolled islanding if not properly studied and identified ahead of real-time operations. It is recommended to expand the stability performance criteria to include both synchronous and asynchronous generation. d. R4.3.2, the standard should recognize that the list of dynamic control devices should consider the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) in stability analyses. The SDT can consider adding asynchronous generator related devices like inverter, plant controller, etc.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Although the cost impact is unknown, costs to Planning Coordinators and Transmission Planners will increase as Transmission System Planning Assessments reflect additional dynamic components and controls. It is anticipated that this cost will vary depending on training, tools, scenario development, and other factors in each Planning Coordinators and Transmission Planners' area.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will primarily impact Transmission System Planning Assessments, not any specific BES facilities, although as individual IBRs continue to increase in size (e.g. 14MW wind turbines), there may be some impact in the near future.
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 Coordinators and Transmission Planners, i.e. the applicable entities for this standard. Additionally, Distribution Providers, Generator Owners, and DER aggregators participating in markets- i.e. not an applicable entity to this standard, would be useful to include.
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.
This SAR is the outcome of the following white paper that was developed by the NERC technical sub-group under the RSTC.

[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
• SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) Deliverables, and the key findings and recommendations contained within, were thoroughly reviewed and approved by the RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
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.
Among all the issues identified in the NERC SPIDERWG white paper, the ones included in this SAR cannot be addressed by any alternatives. Standard language change will ensure DER impacts being considered appropriately. NERC SPIDERWG will prepare a Reliability Guideline to address the rest of the findings from their white paper.

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

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

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

For Use by NERC Only

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

Version History

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

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Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	MOD-032-1 Data for Power System Modeling and Analysis		
Date Submitted:	12/15/2021		
SAR Requester			
Name:	Kun Zhu (NERC SPIDERWG Chair) Bill Quaintance (NERC SPIDERWG Vice Chair)		
Organization:	Kun Zhu – MISO Bill Quaintance – Duke Energy Progress		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.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?):			
As the penetration of distributed energy resources (DERs) continues to increase across the North American bulk power system (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs). MOD-032-1 addresses the gathering of modeling data to perform planning assessments but the standard currently has no specific reference to DER data. This SAR proposes to update MOD-032-1 to: (1) include "data requirements and reporting			

Requested information
procedures"[1] for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise MOD-032-1 to address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments. The goal is to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. The table in Attachment 1 should be updated to include DER in the steady-state and dynamics columns. Details of the changes to be considered by the Standard Drafting Team are included in the "Detailed Description" below. b. Based on item a.) and the detailed description below, the SDT should consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary. c. In alignment with the SAR submitted by the previous NERC Essential Reliability Services Working Group (ERSWG), LSE should be removed and replaced by DP as the applicable entity in Section 4.1.3 and all instances in the standard requirements and attachments. d. The SDT should review any potential gaps regarding data collection for aggregate DER data with the de-registration of LSE or based on applicability transfer from LSE to DP (item c in this list).
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (e.g., research paper) to guide development of the Standard or definition):
This SAR proposes to address the issues identified in the project scope above. Specifically, the following details should be considered and addressed by the drafting team: • In the Applicability section of MOD-032-1, LSE should be replaced with DP, in alignment with the SAR previously submitted by ERSWG. Similarly, all relevant uses of LSE should be replaced with DP.

[1] See Requirement R1 of MOD-032-1, which requires each TP and PC to develop data requirements and reporting procedures for the collection of modeling data used for the development of models for each PC footprint.
[2] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
▪ The table in Attachment 1 should include references to aggregate DER in the steady-state and dynamics columns. The drafting team should consider the data needed for modeling aggregate DER for the purposes of reliability studies. In particular, the drafting team should consider the recommendations set forth in *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. • Note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states "all applicable elements" in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently. • In alignment with adding "DER" to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for "Distributed Energy Resource (DER)" to the NERC Glossary of Terms. As stated, SPIDERWG has published *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies* that includes recommended practices and for the collection of aggregate DER data for transmission planning studies. **These materials are not intended to dilute the criticality of this SAR to address the issues identified above within MOD-032-1 itself. Rather, the SDT can use these materials when determining the specific language for inclusion in the standard requirements revisions.**
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts are not fully known. However, due to the limited scope of the requested data, cost impact is expected to be minimal to all entities. DPs typically collect the information need to model aggregate levels of DERs in planning assessments. Therefore, data collection effort by the DP would be minimal additional effort. DPs already have processes to provide load data to the TP and PC, so DER data can be managed in a similar manner to reduce cost and effort. If the scope of the required data is expanded, cost impact would likely increase.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
DER owners are not subject to NERC Reliability Standards. However, SPIDERWG believes the DP (a NERC Registered Entity) has the information regarding DER connected to its distribution system that is needed for modeling the aggregate behavior of DER for the purposes of BES reliability planning studies. The DP should provide that information to the TP and PC accordingly.
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 Planner, Planning Coordinator, Distribution Provider

Requested information
While not a Functional Entity per the NERC Functional Model, the "MOD-032 Designees" that are designated by the ERO to develop interconnection-wide base cases (i.e., the Regional Entities), will also be affected by these changes and should be considered for appointment to the Standard Drafting Team.
Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The proposals in this SAR were developed by the NERC SPIDERWG, a stakeholder group under the NERC Planning Committee.
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)?
The ERSWG submitted a SAR related to MOD-032-1, as described above. This SAR supports those changes, and further expands on a few necessary additional changes related to DER modeling.
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 NERC SPIDERWG is preparing a Reliability Guideline on data collection for DER modeling. That guideline will provide recommendations for improvements to the data requirements and reporting procedures developed jointly by PCs and their TPs. However, updates to MOD-032-1 are also needed to ensure minimum planning consideration and reporting requirement on DER, particularly in Attachment 1. Therefore, this SAR aligns with the necessary changes to meet the objective.

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.

[3] 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	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

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

For Use by NERC Only

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

Version History

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

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Unofficial Comment Form

Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 Standard Authorization Requests (SARs).** Comments must be submitted by **8 p.m. Eastern, Wednesday, March 02, 2022.**

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

Background Information

Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward.

In general, the impact of DERs on the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or justification.

Questions

1. Do you agree with the proposed scope as described in the SARs? 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 SARs drafting team to consider, if desired.

   Comments:

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Standards Announcement

Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 Standard Authorization Request

Comment Period Open through March 02, 2022

Now Available

An informal comment period for the **Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1** Standard Authorization Requests (SARs), is open through **8 p.m. Eastern, Wednesday, March 02, 2022**.

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 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 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:	2022-02 Modifications to TPL-001-5.1 and MOD-032-1 | SARs
Comment Period Start Date:	2/1/2022
Comment Period End Date:	3/2/2022
Associated Ballots:	

There were 39 sets of responses, including comments from approximately 126 different people from approximately 88 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SARs? 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 SARs 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
Santee Cooper	Chris Wagner	1,3,5,6		Santee Cooper	LaChelle Brooks	Santee Cooper	1,3,5,6	SERC
					Rene' Free	Santee Cooper	1,3,5,6	SERC
					Anthony Noisette	Santee Cooper	1,3,5,6	SERC
Electric Reliability Council of Texas, Inc.	Dana Showalter	2	Texas RE	ISO/RTO Council (IRC) Standards Review Committee (SRC) 2022-02 SAR	Bobbi Welch	MISO	2	RF
					Ali Miremadi	CAISO	2	WECC
					Dana Showalter	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Helen Lainis	IESO	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Elizabeth Davis	PJM Interconnection	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
Entergy	Julie Hall	1,3,6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	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
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	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
Florida Municipal Power Agency	LaKenya VanNorman	1,3,4,5,6	SERC	FMPA and members	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Richard Montgomery	Florida Municipal Power Agency	6	SERC

					Larry Watt	Lakeland Electric	1	SERC
					Carolyn Woodard	Beaches Energy Services	3	SERC
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
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Frazier	1,3,5,6	MRO,NPCC,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
					James Howell	Southern Company - Southern Company Generation	5	SERC
Eversource Energy	Quintin Lee	1,3		Eversource Group	Quintin Lee	Eversource Energy	1	NPCC
					Christopher McKinnon	Eversource Energy	3	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC

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

					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Jim Grant	NYISO	2	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc.	2	MRO
					Ellen Cook	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc.	2	MRO

					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Sunny Raheem	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Doug Bowman	Southwest Power Pool Inc.	2	MRO
Lower Colorado River Authority	Teresa Krabe	1,5		LCRA Compliance	Michael Shaw	LCRA	6	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Teresa Cantwell	LCRA	1	Texas RE

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

Thomas Foltz - AEP - 3,5,6	
Answer	No
Document Name	
Comment	

AEP is in agreement with the scopes and directions of the two proposed SARs for TPL-001, and recommends that Project 2022-02 be governed by their content. This would presumably be done by combining the content of these two unique SARs into a single SAR. AEP is not in agreement however with the proposed SAR for MOD-032, and recommends it *not* be pursued for this project for the reasons and rationale provided below.

1) As stated in a previous comment period for Project 2020-01, we believe MOD-032 is already written in a way that allows DER data to be obtained for power system modeling and analysis, if that data is available. The existing requirements for Transmission bus delivery points already include obligations for the Distribution Provider (DP) at that Transmission bus to separate out in its report to the RTO, the Distribution-connected generation capacity from the demand capacity appearing at that Transmission bus.

2) While the SPIDERWG SAR for MOD-032 does correctly acknowledge that DER owners are not themselves subject to NERC Reliability Standards, it incorrectly presumes that a) the data is already being provided by all entities who are not required to provide it, b) the DPs currently possess all the desired DER data, and c) the “data collection effort by the DP would be minimal additional effort.” This is simply not the case, and was voiced by industry in the comments provided two years ago when the MOD-032 SAR was proposed for Project 2020-01 (the Standards Committee eventually rejected the SAR that year “for good cause” in their letter to the SAR’s authors). In addition, the SPIDERWG SAR for TPL-001 states “In general, the impact of DERs on the BES should be included in planning assessments *if* DER data and models are available.” Contrary to the SAR for MOD-032, this quote does correctly acknowledge that the DER data will not always be available, but that same understanding is not also applied to the SAR for MOD-032. Many of the entities that the TP would rely on for this DER data are not themselves NERC Functional Entities, nor are they obligated by NERC requirement(s) to provide such data. In addition, many generators that have historically been considered load-augmenting in most cases, would now qualify as DER. As a result, these entities which have had no previous obligations to provide information to NERC Registered Entities would now be relied on to do so. However even after MOD-032’s potential revision, since they are not NERC registered entities, these generators would still have no NERC obligations to provide such data. This being the case, if this SAR is pursued as currently drafted, the Transmission Planner presumably bears all risk associated with whether or not that data is provided to them. If this SAR is indeed pursued, the SDT must ensure the Transmission Planner does not assume any risk associated with “non-obligated entities” not providing that data to the TP.

DER data is uniquely specified by RTO tariffs, and authorized by each state’s commission. This data is provided to the RTOs by NERC-registered entities as well as entities which are *not* registered as NERC entities. As such, if any entity should be responsible for the collection and dissemination of such data for system modeling purposes within NERC obligations, it should be the RTO and *not* the Distribution Provider.

Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 1,3,6, Group Name Entergy	
Answer	No
Document Name	

Comment
TPL-001-5.1 IRPWG SAR Comments: Suggest adding clarity that TP depends on the data provided by the GO for an IBR facility (i.e., the trip settings at the low side of the GSU). The TP should not be expected to convert the data to the high-side. (R4.3.1.2) **TPL-001-5.1 SPIDERWG SAR Comments:** R4.1.1 & R4.1.2 language does not align with changes proposed in the TPL-001-5.1 IRPWG SAR. Some DERs with legacy settings (not required to abide by PRC-024) may not be able to ride through a close fault in any circumstance. These DERs will not be able to meet P1 criteria and need to be clearly excluded in the performance requirements. **MOD-032-1 SAR Comments:** The definition of DER should make a distinction between aggregated customer solar installations (e.g., residential rooftop solar, etc.) and commercial solar installations connected to distribution.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment
With respect to the proposed SAR, MOD-032-1 Data for Power System Modeling and Analysis, the only suggested modification that we agree with in the list of proposed work is adding the Distribution Provider (DP) to the scope of applicability so that modeling information can be obtained by the planners for retail connected distributed energy resources (DER). We believe that everything else in the proposed work is not needed. The specification of DER equipment and details related to it are not needed in the standard. Requirement R1 of the existing version specifies that the PC/TP develop modeling data requirements and reporting procedures including the data in Attachment 1. The steady state and dynamic sections of Attachment 1 both include this line item: "Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]" This item gives the PC/TP the authority to ask for the modeling information they deem necessary to build the cases and to perform their studies. Because of this, no modification to the standard is needed to itemize the DER modeling information. In summary, including the Distribution Provider in the applicability section of MOD-032, in Requirements R2 & R3 of MOD-032, in item 9 of the steady-state data column of Attachment 1 of MOD-032, and in item 10 of the dynamic data column of Attachment 1 of MOD-032 will sufficiently permit the PC/TP to request what modeling data it needs for DER from the DP and from the GO. With respect to the proposed modifications to TPL-001-5 described in separate SARs of the same title and submitted by representatives of the IRPWG and SPIDERWG, TPL-001-5.1 Transmission System Planning Performance Requirements, clarifications to terminology (e.g., “pulls out of synchronism” and “GSU transformer”) does not address an immediate risk to BPS reliability. These types of modifications should be considered in a future revision to the standard.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	No
Document Name	
Comment	

MOD-032 SAR:

- Modification to MOD-032 appear to be prudent to ensure clarity on what entities should provide the PC regarding DER.

IRPWG TPL SAR:

- In general, the recommendations in the SAR are aimed at clarifying the requirements to ensure they are inclusive of IBR. These modifications do not appear to change the intent of the current standard language so they should not prompt the opening of the TPL standard but should be considered whenever the standard is open for more substantive modifications.
- The SAR cites the IRPTF whitepaper and states, “the term GSU transformer can be confusing to GOs…” The GO function is not applicable to the TPL standard so it is not clear how this term being included in the TPL standard would be confusing to GOs.
- The recommendations regarding “pulls out of synchronism” and the proposed modification to R4.3.2 provide clarifications that are appropriate for the standard and should be considered if the TPL standard is open for more substantive updates.

SPIDER TPL SAR:

- The comments for the IRPWG apply here as well.
- The recommendations around “System Peak Load” refer to potential new glossary terms and a change of the use of the term within the TPL standard. The benefits of adding qualifiers like “net” or “gross” are not clear relative to the time and effort modifications to the TPL standard would require. The current language in the standard allows a measure of discretion in the determination of “peak” load to be modeled that planners can use as appropriate in their respective areas.
- The penetration levels of DER at which potential BPS problems occur and the resulting impacts to the BPS are not clear. Prior to opening the TPL standard for substantial modifications, more guidance is needed for different sections of the industry (with varying penetration levels of DER) that define potentially problematic penetration levels of DER.

Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	No
Document Name	
Comment	

SPIDERWG MOD-032-1 SAR Comments

{C}· ATC supports the collection of DER data for steady-state and dynamics modeling. Setting a guideline that calls out best practices for DERs is a very important step toward obtaining detailed and representative modeling data. This will hopefully get industry moving in the right direction so that Transmission Planners and Planning Coordinators have something to leverage with Distribution Providers when collecting information.

- A mechanism to require behind-the-meter IBR and DER to report data to Distribution Provider does not exist.
  - ATC supports SAR language to use the DER data if it is available. ATC cautions against requiring Transmission Planners to have/ use data that may not be obtainable from the Distribution Provider (who may not be able to collect it from the DER).
  - Planning Coordinators should require DER data collection in their MOD-032 data collection requirements.
  - Due to the challenges associated with the collection of distribution-level data, consideration needs to be given to screening criteria and/or the ability to aggregate data to allow for efficiency and effectiveness such that the technical benefits received are commensurate with the cost of obtaining the data.
- ATC agrees with Item D of the Scope: "The SDT should review any potential gaps regarding data collection for aggregate DER data with the de-registration of LSE or based on applicability transfer from LSE to DP."
- ATC supports the SAR scope's proposal to consider including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms.
- The SAR drafting should consider the inclusion on non-BES generators in the scope.

IRPWG and SPIDERWG TPL-001-5 SAR Comments

- ATC supports setting a guideline that calls out best practices for DERs is a very important step toward obtaining detailed and representative modeling data. This will hopefully get industry moving in the right direction so that Transmission Planners and Planning Coordinators have something to leverage with Distribution Providers when collecting information.
- Under SPIDERWG TPL-001-5 SAR Item C of the Scope "R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER", if tripping criteria is required for DERs, it should *only* be applicable under NERC cascading conditions.
- PRC-024-3 differentiates GSU from Main Power Transformer for Quebec but FERC documents with (LGIAs, 661-A, etc.) use GSU to mean Main Power Transformer.
  - The SAR and/ or Drafting Team could consider the language PRC-024-3 uses in Attachment 2: "… voltages at the high side of the GSU/MPT. For generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer with a low side below 100 kV and a high side 100kV or above."
- ATC agrees that the terms Gross Load and Net Load should be defined in the NERC Glossary of Terms, and consideration should be given to the timing of peak load occurrence shifts with increased DER presence. However, if the requirements are changed to specify "System peak net load", then Gross Load conditions would only be studied as a sensitivity and may not be considered under latter requirement (such as development of associated Corrective Action Plans).

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation has concerns on the expansion of scope in the SAR to include all DER's as that can expand further than DER's subject the NERC Compliance under MOD-032-1.
Constellation agrees with NAGF's comments regarding the majority of DERs are not subject to NERC compliance. "Though the NAGF generally agrees with the proposed scopes of these SARs, the NAGF has concerns with the DERs providing information as DERs are not subject to NERC compliance or these standards. As such, requiring entities (i.e. DPs) to acquire such data should not have compliance obligations or accountability in situations where the DERs do not comply with the request(s)."
Constellation also asserts that the NERC Reliability Guidance "Improvements to Interconnection Requirements for BPS-Connected Inverter Based Resources" of Sept 2019 has good guidance to Transmission Owners to derive the data that is being considered in this SAR.

Kimberly Turco on behalf of Constellation Segments 5, 6

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI does not support the entirety of the proposed scopes of the three SARs. All references to BPS should be removed from these SARs. While we understand the motivations and perceived need for including this language, the scope of NERC Reliability Standards, as defined in FERC Order 693 (see P75), is limited to the Bulk Electric System. Moreover, the scope of these Reliability Standards cannot be expanded within the scope of a single NERC Standards project.

Additionally, EEI suggests the use of composite load models as a viable option to address the difficulties of collecting DER information from unregistered entities. Such an approach is a reasonable option until the jurisdictional issues can be resolved.

Please see EEI’s comments for the three SARs in our response to question 2 below.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power agrees with MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

AZPS does not agree with the scope of the proposed SARs as written. AZPS is particularly concerned with references to the BPS instead of the BES which is commonly used through the NERC Reliability Standards. This is problematic because registered entities such as the PC, TP, and DP do not have any authority to collect data from non-BES resources as they are not registered and have no obligation to provide requested data.

AZPS agrees with EEI's comments that "the scope of NERC Reliability Standards, as defined in FERC Order 693, page 75, is limited to the Bulk Electric System. Moreover, the scope of these Reliability Standards cannot be expanded within the scope of a single NERC Standard project."

TPL-001-5.1 IRPWG SAR

AZPS recommends that BPS-connected inverter-based resources should be changed to BES inverter-based resources throughout the SAR. This is consistent with the statement in the last paragraph of the Industry Need Section which states, "This SAR does not include any modification to TPL-001-5 regarding the inclusion of distributed energy resources (DERs)."

AZPS believes that expanding the scope of the term "GSU Transformer" within the standard would create unnecessary confusion. AZPS recommends adding the term Main Power Transformer (MPT) to the standard as was done in PRC-024-3 (see Section 4.2.1.6 and footnote 1), instead of expanding the scope of the term GSU.

In regard to the Project Scope section, AZPS agrees with EEI's comment that entities should not be "required to maintain lists of all devices that might impact the study area inclusive of BPS-connected inverter-based resource technologies. This represents a substantial burden that goes beyond what entities can reliably collect."

TPL-001-5.1 SPIDERWG SAR

AZPS recommends that the term BPS-connected generation be changed to BES-connected generation in the first paragraph of the Industry Need section and that the term BPS Planning be changed to BES Planning in Footnote 1.

In regard to Item b of the Project Scope section, AZPS supports the following EEI comments:

The SAR “does not clarify the concern contained in the reference SPIDERWG whitepaper or provide clear language that an SDT could act upon.”

The SAR also “states that the SDT should “include tripping of DER if data and models are available,” however, there are no methods contained within any Reliability Standard that would define how PCs or TPs could collect this data. While we understand that some transmission tariffs may provide viable methods for collecting some of this data from Transmission Service Providers (TSP), this is tariff dependent and cannot be universally relied upon. Therefore, it is unclear how these two entities would have sufficient data to perform an effective planning study in most regions.

The second sentence in Item b states that the SDT should consider whether a threshold needs to be established, however, the SAR does not clarify what threshold should be considered. In the whitepaper, it states that “no specific threshold for DER modeling is suggested, each entity should keep track of DER to make such determinations.” Given the whitepaper is the basis for the SAR and “no specific threshold is suggested” we suggest this statement be removed.”

In regard to Item C, AZPS recommends that the language contained in subparts 4.1.1 and 4.1.2 be changed to consider BES Inverter-based resources only as there are currently no provisions that would ensure that PCs, TPs, or DPs have any ability through the NERC Reliability Standards to collect sufficient data to conduct the planning studies envisioned.

In regard to Item D, AZPS does not agree that DER’s should be included as they are outside the registration criteria and are not required to provide the data required to perform an accurate stability analysis. To address this concern, AZPS suggests a more practical approach is to use generic load models such as the composite load model based on known nameplate data using engineering judgement.

MOD-032-1 SPIDERWG SAR

AZPS supports the addition of the DP function to support the deregistration of the LSE function but does not support the proposed SAR because it lacks supporting technical justifications, such as a white paper describing what, if any, reliability gap exists.

AZPS also supports the following comments submitted by EEI:

EEI disagrees with Item 3 contained within the Industry Need statement. There is no need to “review any additional gaps in DER data collection with the de-registration of LSE.” Such a review is inconsistent with the FERC order (153 FERC ¶ 61,024) approving the removal of LSEs from the functional registration. Notably, RCs, BAs, and REs and other affected entities that need the information from LSEs had no concerns if LSEs were no longer registered. The working group should take notice of the FERC conclusions and findings in this order.

EEI disagrees with the Purpose and Goal statement. Specifically, it is not clear what gaps within the currently approved MOD-032-1 beyond the need to add the DP function, exist.

Attachment 1 – Data Reporting Requirements within MOD-032-1 do not need to be updated. Steady-State (Item 2 and Item 9), and Dynamics (Item 10) provide sufficient flexibility for PCs and TPs to ensure that DER data is collected. We further note that these items provide sufficient latitude in what is collected. “Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP].

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation has concerns on the expansion of scope in the SAR to include all DER's as that can expand further than DER's subject the NERC Compliance under MOD-032-1 Constellation agrees with NAGF's comments regarding the majority of DERs are not subject to NERC compliance. "Though the NAGF generally agrees with the proposed scopes of these SARs, the NAGF has concerns with the DERs providing information as DERs are not subject to NERC compliance or these standards. As such, requiring entities (i.e. DPs) to acquire such data should not have compliance obligations or accountability in situations where the DERs do not comply with the request(s)." Constellation also asserts that the NERC Reliability Guidance "Improvements to Interconnection Requirements for BPS-Connected Inverter Based Resources" of Sept 2019 has good guidance to Transmission Owners to derive the data that is being considered in this SAR.

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 North American Generator Forum (NAGF) understands the need for and supports including Distributed Energy Resources (DERs) and BPS connected inverter-based resources in planning assessments where such data is made available. The NAGF has concerns as it relates to the SAR proposed for MOD-032-1 as well as the TPL-001-5.1 SAR proposed by the SPIDERWG:

- *The NAGF has concerns with the DERs providing information as DERs are not subject to NERC compliance or these standards. As such, requiring entities (i.e. DPs) to acquire such data should not have compliance obligations or accountability in situations where the DERs do not comply with the request(s).*
- *The steady-state and dynamic sections of Attachment 1 for MOD-032-1 already contain the following line item: "Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes [BA, GO, LSE, TO, TSP]." This item provides the PC/TP the authority to ask for modeling information they deem necessary to build the cases and to perform studies. Therefore, no modification to the standard is needed to itemize DER modeling information.*

The NAGF agrees with the proposed scope of the TPL-001-5.1 IRPWG SAR to improve language and provide clarity for inverter-based resources.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF understands the IPRWG concerns and intent to consider Distributed Energy Resources (DERs). While the MRO NSRF appreciates the issues the SARs are attempting to solve and good intentions, NERC regulated entities must deal with the final zero-defect product enforced by auditors for a large, diverse, and rapidly changing population. This is a poor fit for zero-defect standards.

IRPWG SAR Responses:

- The MRO NSRF believes that a solution can be achieved, but the SAR as currently written must be revised.
- BPS cannot be allowed and needs to be replaced with BES.
- Lists cannot be allowed and maintained to zero-defect due to the large, diverse, and ever-changing nature of DERs.
- Regulatory jurisdiction issues must be overcome.
- At least one solution in any future NERC standard requirements must allow flexibility for the DP, TP, and PC to use its engineering best judgment to develop composite load models and the SAR scope must explicitly state that.

IPRWG SAR Required Modifications for NERC standards and DER to be enforceable:

- The MRO NSRF can support certain aspects of the IPRWG SAR, but not the SAR itself without modifications.

o Bulk Power System (BPS) cannot be used in SARs or NERC standards and must be replaced with Bulk Electric System.

o BPS is undefined, which is why BES was created and debated carefully.

o Distributed Energy Resources are by NERC's own definition are part of the distribution system.

- A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).
- https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

o The 2015 Federal Power Act (FPA) forbids "facilities used in the local distribution of electric energy" to which DERs are connected.

- DERs must first be subject to the same regulatory penalty structure as NERC registered entities or zero-defect standards are unenforceable.

o Regardless of good intentions, without equal enforcement penalties, DERs do not have the same incentive to provide data to NERC Distribution Providers, Transmission Planners, or Planning Coordinators.

o Zero-defect is by definition, without error.

o DERs are small and will change constantly, rendering lists useless. When a DER goes bankrupt, disappears or changes, data may not be communicated.

- Listing BPS devices cannot be required.

o For the reasons stated above, a zero-defect list cannot be perfectly maintained.

MRO NSRF Can Support:

- Clarifying pulling out of synchronism is for synchronous generators only.
- Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term "GSU transformer" suitable for all generation types.

Technical Issues:

The SAR had requested entities note any technical issues.

- Decades of load research have shown that generic load model assumptions provide the best approach to simulating loads.
- Whether mercury vapor lights, compact fluorescent lights, LEDs, or power electronics, achieving a good cost-to-benefit ratio for specific load data has always been difficult. Detailed load surveys are expensive and time-consuming, often yielding only marginal benefits above engineering judgment by experienced Transmission Planners.

Alternatives:

- A revised SAR must state specifically the resulting NERC standard requirements will explicitly allow flexibility with DP, TP, and PC engineering judgment discretion for composite load models as a solution.
- FERC could require FERC registered entities to submit DER data to DPs, TPs, and PCs or face penalties similar to NERC registered entities to provide the same incentives to the small DERs to provide the required data.
- NERC could publish a white paper on best practices, not subject to mandatory enforcement that NERC DPs, TPs, and PCs provide their best estimates of DER impacts in composite load models.

SPIDERWG and MOD-032 SAR Responses:

The MRO NSRF supports the intent of the SARs. Following the repeated recurrence of major events involving Inverter-Based Resources (IBRs), there is an industry need to be able to accurately model IBRs and aggregated Distributed Energy Resources (DERs) in the planning horizon to identify risks and develop plans to mitigate them prior to those risks giving rise to events in the operating horizon, particularly with respect to IBRs. However, there are two main issues that should be addressed by the SDT:

- **Approach to data collection/modeling**
- **Replace all references to Bulk Power System with Bulk Electric System**

Approach to Data Collection / Modeling:

The NSRF proposes the SAR not require a granular approach to data collection which contemplates zero-defect compliance and instead focus on a risk-based approach that would result in efficient and effective aggregated modeling data. Due to the challenges associated with the collection of distribution data, consideration needs to be given to screening criteria and/or the ability to aggregate data to allow for efficiency and effectiveness such that the technical benefits received are commensurate with the cost of obtaining the data. These fundamental issues (a better framework, better performance standards and better enforcement that recognizes most data collection issues are low risk) must be implemented for industry or regulators to avoid being pulled into the meticulous examination of each piece of data provided.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	

Tri-State appreciates the opportunity to comment on the three SARs and understands the concerns with Distributed Energy Resources (DER).

IRPWG SAR

Tri-State generally agrees with the SAR except for the below:

- Bulk Power System (BPS) should be replaced with Bulk Electric System (BES). BPS is not defined and should not be used in the SAR.

SPIDERWG/MOD-032 SAR

Tri-State does not agree with the SPIDERWG SARs:

- Unless you reach a certain threshold DER models are not required so more times than not you will not have a model. Concern is how do you monitor performance if you don't have model data. There has to be certain thresholds in place and also what changes a threshold. Most importantly, because DERs are not being subject to any regulation the incentive to provide data/modeling is very small. There has to be an incentive for DERs to provide data.
- Bulk Power System (BPS) should be replaced with Bulk Electric System (BES). BPS is not defined and should not be used in the SAR.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3

Answer	No
Document Name	

Comment

Exelon supports this project and the efforts of the IRPWG and the SPIDERWG. We do not agree with the proposed scope in part due to the reference to the Bulk Power System (BPS). We concur with the comments on this concern provided by the EEI.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1,3, Group Name Eversource Group

Answer	No
Document Name	

Comment

The term Bulk Power System lacks the clarity of Bulk Electric System, suggest changing BPS to BES.

It should be clear the DER data is for the Transmission Planner not SCADA data for the Transmission Operator.

See comments in Question 2 for more details for each SAR.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Add a definition for “Distributed Energy Resource (DER)” to the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE appreciates the drafting team’s efforts to account for inverter-based resources (IBR). Texas RE agrees with the purpose and justification of the three SARs presented. Texas RE has a few specific comments regarding the SAR scopes.	

First, Texas RE noticed that the IRPWG SAR discusses clarifying the term “GSU transformer”. Texas RE generally supports clarifying terms, and appreciates the SDT’s efforts in this regard.

Second, Texas RE also agrees the requirements should clarify whether they are applicable to DERs. As part of this process, the SDT could consider defining the term “DER.”

Finally, while Texas RE agrees with the TPL-001-5 IRPWG SAR regarding synchronization being more applicable to non-IBR machines, the SAR team should consider evaluating whether there is a corresponding attribute of IBRs that needs to be captured effectively in planning reliable operation of the grid. The SPIDERWG SAR partially addresses this issue with the recommendation to expand the stability performance criteria for synchronous and asynchronous generation.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy - while supporting the scope in the SARS - supports EEI's request for clarification and changes to the three SARS.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - Florida Municipal Power Agency - 1,3,4,5,6 - SERC, Group Name FMPA and members

Answer	Yes
Document Name	

Comment

FMPA generally supports the present high-level proposals in the SARs. As details are developed in the actual standard language, we will review to ensure we agree with the way the changes are implemented. We explicitly support the concept of including thresholds for DER inclusion, since in many regions penetrations are still very low.

Likes 0	
Dislikes 0	

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

For the MOD-032 SAR, we generally agree with the proposed project scope but have the following comments:

The *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies* referenced in the SAR notes a distinction between utility-scale DERs (U-DERs) and retail-scale DERs (R-DERs). It states that the distinction is "based on their size, impact, or location on the distribution system". We suggest that another distinction to consider is ownership of the DER. Is the DER owned by an electric utility, an end-use (industrial, commercial, residential) consumer of electricity, or a DER owner/aggregator/provider? The project proposal to "consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary" is perhaps all that can be stated at the SAR stage; however we believe an industry vetted definition is important if the term is going to be added to the MOD-032 standard. It is presumed that modeling data for U-DERs will be more readily obtainable than for R-DERs.

The SAR states that "The goal is to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data." There may be instances where DERs are owned by or installed under programs coordinated by a utility that is registered for a broader set of NERC functions (not just registered as a DP). In such instances, a registrant that is only registered as a DP may not be the most practical source for the modeling data needed by the PC and TP, but they would be subject to the standard. The NERC Compliance Registry dated 2/11/2022 reflects there are 316 registered DPs, of which 68 are registered only as a DP. An additional 70 entities are registered as "UFLS-Only DPs". Could a new "DER-only DP" registration sub-category be needed for the DP? An alternative approach for the MOD-032 standard would be to add a "DER data entity" to the applicability section (similar to PRC-006-5's section 4.2). Then such entities "could include one or more of the following.... (DP, UFLS-Only DP, TO, RP, GO, ???)".

The MOD-032 SAR should also include removal of the "Planning Authority" and related PA / PC explanation from section 4.1.4 of MOD-032 within the scope. This would be consistent with action taken on MOD-031 and MOD-033 under Project 2017-07, Standards Alignment with Registration.

For the TPL-001 SARs, we generally agree with the proposed project scopes but have the following comments:

The SAR submitted by the SPIDERWG proposes to replace the phrase "System peak Load" with "System peak net Load" in TPL-001-5.1, R2.1/2.1.1 and R2.2/2.2.1. We interpret this to mean that models representing DER adjusted loads would be treated as the "baseline" representation for assessing the system and scenarios without DER adjusted loads would be treated as a sensitivity case (with sensitivity cases only required for the Near-Term Transmission Planning Horizon). We believe that each TP, in consultation with their PC, should be allowed to determine the appropriate assumption for DERs to be used in their baseline study models. Some may prefer to utilize models with DER adjusted loads represented as a sensitivity case. As greater confidence is gained in the DER data received by the PC/TP, along with a review of historical DER performance/event response, using models with DER adjusted loads as the "baseline" could become the norm.

The SAR submitted by the SPIDERWG proposes that the "tripping of generators" in steady state (R3/3.3.1.1) and stability (R4/4.3.1.2) contingency analysis should include tripping of DER if data is available. We believe the phrase "if data and models are available" is an important distinction that should carry over into the standard. This tripping of generators makes sense if the planners have the data, a definition of DER; and a specified threshold.

The SAR submitted by the SPIDERWG proposes that the stability performance criteria (R4/4.1.1, 4.1.2) should be applicable to both synchronous and asynchronous generation, inclusive of DER. The standard currently states that a generator disconnected by "fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism." This language appropriately emphasizes that pulling out of synchronism is the consequence to be avoided. While loss of inverter-based generation could cause challenges for system operators, that impact is similar to the loss of generation due to fault clearing or a Remedial Action Scheme; it is not the angular stability of any generating unit that is at risk, but instead a possible

power deficit that must be supplied from other generators. The original intent of the standard was to distinguish the extra impact to the grid when the swing of a synchronous generator was pulling out of synchronism and causing a potential low voltage and out of step condition. This type of impact is not present when a nonsynchronous generator is tripped offline due to an event. Moreover, specifically in respect to DERs being included in R4.1.1 and R4.1.2, these generators are not part of the BES. While tripping these resources may be appropriate to understand BES impacts, the loss of non-BES generation should never be considered a BES violation.

The SAR submitted by the SPIDERWG proposes that for R4/4.3.2, the list of dynamic control devices should include DER so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses. The standard currently states that the operation of dynamic control devices is required when "such devices impact the study area." It is important that planners be able to rely on documented assumptions in determining which devices should be modeled. Obtaining accurate modeling data for DERs is challenging and for many DERs may result in negligible impact to the BES. Thus, it is important that the addition of DER controls to R4.3.2: 1) be accompanied by a qualification that the modeling data is available, and 2) retain the ability to exclude facilities where the dynamic control devices do not impact the study area.

Likes 0	
Dislikes 0	

Response

Scott Brame - North Carolina Electric Membership Corporation - 3,4,5 - SERC

Answer	Yes
Document Name	

Comment

NCEMC generally agrees with the proposed scope as described in the SARs, but we have concerns about how these 3 SARs have been proposed to be addressed with only one SAR SDT, mainly that the make-up of the SDT will most likely be a majority of PC/TP representatives and not very many DPs will participate as very few DPs will be interesting in working on activities they are not subject to or have much interest (since there are two SARs for TPL-001-5.1 in this case). Plus the amount of time it may take to address the various and complex issues in the TPL SARs and the MOD SAR may take many meetings over numerous months and very few companies if any has sufficient resources to allow a staff representative to be out-of-pocket working on this project for numerous months. We strongly suggest that NERC and the leaders of this SAR SDT carefully consider how best to address the specific items identified within the SAR and make every effort for this Project not to wander beyond what is specifically stated in the SARs to do.

Additionally, because of what happened on the 2020-01 Project SAR SDT for MOD-032-1 only seeking "informal comments", we would have preferred that NERC had requested "formal comments" first for each of these SARs as a possible means to better gauge industry support to avoid the potential situation of having the SAR being rejected as what happened for Project 2020-01. For Project 2022-02, we would strongly encourage NERC to consider having multiple comment rounds before these SARs are taken back to the NERC Standards Committee for vote/approval on how to move forward. As a member of that SAR SDT, it was disappointing when the NERC SC decided to reject the SAR completely and disband the SAR SDT when only "informal comments" were requested. Maybe NERC has already addressed this in the SPM manual to prevent this incident from being repeated. Many of the reliability issues regarding DERs re-surfaced in the NERC Odessa Disturbance report as well as the NERC Inverter-Based Resource Performance Task Force (IRPTF) White Paper before the Odessa event occurred. In our opinion, coordinated Transmission - Distribution Planning is not being done in a proactive manner as it once was and it needs to be for various reasons, but one reason has to do with a lack of consistency and uniformity for how increasing DERs are accounted for that have already interconnected to the BPS and are still being interconnected. Additionally, it seems that DERs are being allowed to exhaust any and all surplus/overhead capacity to the BPS and as a result, network and native load is continuing to be put at risk if they don't have sufficient resources to back-up their primary supply source located at or near the load delivery points.

As for extending the MOD-032-1 to the Distribution Providers (DP) since the Load-Serving Entity (LSE) function was retired by NERC (LSEs still exists in the OATT world for NITS customers performing the DP function), simply extending this standard and several other standards as noted in the NERC Inverter-Based Resource Performance Task Force (IRPTF) White Paper to the DP function does not go far enough to address the ongoing complex

issues associated with collecting and modeling of aggregate DERs in powerflow models used for seasonal reliability assessments and long-term transmission planning. PC/TP entities are responsible for providing a procedure and mechanism for collecting any and all modeling data needed for carrying out long-term planning. Today, the modeling standards MOD-031 and MOD-032 each already allow the PC/TP to request this DER/DR data from anyone taking transmission service from their grid. They have item 9 in Table 1 of MOD-032-1 which allows to ask for “any other data” and that can include DER, DSM or DR or any behind-the-meter resource for that matter. Distribution Providers are not always party to the DERs interconnected to the Transmission or Distribution so assuming that DPs have the authority to request data from DERs is not an accurate assumption. Does every standard have to explicitly include a reference to DERs to allow the PC/TP to request it? There has to be additional accountability to address the coordination issues (or lack thereof) between DPs and GOs (or “data providers”) and TOs and their respective PCs/TPs to accurately account for DERs explicitly or in aggregate. We have observed that often the “model builders” may not account for the full MW capacity value of the DERs interconnected to the BES or BPS as they appear to be assuming either ELCC or a “Capacity Value at Peak” Study for DERs or IBRs or assuming some sort of “engineering judgment” to reflect something less than the full MW output of DERs coincident with the transmission/system peaks (winter and summer). It seems to be something that is far less than what the DER or IBR was studied during interconnection and is capable of producing to the grid. This is “without” any discussion or exchange of information between the DER and/or asset owners of this facility or the local Distribution Provider. Why is that? Why not account for the max output of the DERs or IBRs during sensitivities assumed for “worse case” under contingency “stress tests” for identifying system weaknesses rather than simply “assuming” that scenario may never happen OR the grid is suddenly in an unanalyzed state(s) and you would then have to resort to curtailment of that DER/IBR assuming there is proper SCADA or isolating devices to enable the DER/IBR to be reduced or tripped offline? Why assume this rather than test for the possibility and mitigate it the best you can? Collectively, all utilities in all states should not and cannot simply rely on the LGIA and SGIA agreements and GI queue processes that “sometimes” trigger “affected system studies” to properly account for DERs needed to be modeled in powerflow models used for reliability assessments and long-term planning.

For the TPL SAR, we still have concerns about the TPL standard being revised to allow for only planning to the “net load” (defined as “net load = gross load – DER output”) as seen at the T-D interfaces versus gross load observed during the transmission system peaks. The load profile at the T-D interface is NOT or is rarely going to be the same as the energy profile of any behind-the-meter DER. From recent comments shared with the RSTC about this SAR, it seems to be proposing a provision to allow the PC/TP entities to ONLY plan for high system “net” load (whatever that means) that may or may not account for periods when the sun is NOT shining thus no output provided by that solar DER. If PC/TP entities only plan to trigger upgrades for the “net load” then this may drive us all to a point where the net T-D interface load at all T-D substation/delivery points become flat or even decreasing over time (if it is not already experiencing that phenomena) which could mask loading and stability issues that would have otherwise been accelerated needed network transmission upgrades had it not been for the modeling practice of accounting for DERs below the BPS “only” in the substation/POD load forecasts assumed across the planning horizon.

Perhaps it may take a FERC Technical Conference (there may have already been some at this point) to reach a point where dealing with the “identified reliability gap claimed by NERC” in a manner such that it is not overly burdensome to any NERC-registered reliability party while also accounting for non-FERC and non-NERC registered DER/IBR asset owners and developers. If that is what is needed, then NCEMC would like for NERC and FERC to hold such conference(s) with local/state regulators sooner rather than allowing this “reliability gap” to continue to persist and trigger yet another reliability event like the ones in Southern California and Odessa, Texas.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	Yes
Document Name	

Comment

Recognizing the impact of increased use of inverter-based resources, ISO New England supports the proposed SARs to modify the MOD-032 and TPL-001 Standards. Since many inverter based resources are less than 20 MVA for a single unit or 75 MVA aggregate with connections at less than 100 kV, these smaller resources should be taken into consideration when revising the TPL-001 and MOD-032 Standards.

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC) 2022-02 SAR

Answer	Yes
Document Name	

Comment

The Standards Review Committee (SRC) of the ISO/RTO Council supports the need to modify TPL-001-5.1, as identified in the IRPWG and the SPIDERWG Standard Authorization Requests (SARs) associated with this project. With the continued increase of Inverter-Based Resources (IBRs) and Distributed Energy Resources (DERs), Planning Assessments require consideration of the reliability impact of these facilities on the BPS. However, additional data is required to ensure useful assessments, which leads into the importance of modifying the data collection requirements of MOD-032.

TPL-001 (IRPWG and SPIDERWG SARs)

The SRC believes TPL-001 Requirements 4.1.1 and 4.1.2 should be addressed, but could be clearer on the direction. The IRPWG SAR stated the requirement should be clarified to address only synchronous generators. The SPIDERWG SAR stated that these requirements should be expanded to include asynchronous generation. There are two issues embedded here and the SRC believes each should be addressed separately by the Standard Drafting Team: (1) Requirements 4.1.1 and 4.1.2 should be clarified to apply to synchronous generators only and (2) additional criteria should be established for asynchronous generation and inverter-based resources connected at both the BPS level and at the transmission/distribution interface.

For Requirement 4.3.2, both SARS suggested expansion of the list of devices to be considered in the analyses to include the impact of automatic operation of DERs and IBRs. The SRC suggests that, in addition to the scope of the SARs provided by the IRPTF and SPIDERWG, the Standard Drafting Team consider a stronger stance than the current “devices may include . . .” if these devices are expected to be included in the contingency analysis required in Requirement 4.3. Otherwise, this seems to be optional or informative and would be better to be in a guidance document.

Regarding Requirements 3.3.1.1 and 4.3.1.2, the SRC would like to ensure the Standard Drafting Team ensures the standard includes large DERs as well as aggregation of smaller DERs. Further, the SRC would like to see the SAR provide for a standard broad enough to allow appropriate Responsible Entities the ability to develop a pre-screening process, methodology and/or criteria to identify when there is a need to further study DERs that could have a meaningful impact on the reliability of the BES, as opposed to requiring a comprehensive study be done to assess all DERs regardless of impact. With this methodology or criteria, Responsible Entities such as the Planning Coordinators (PCs) could establish both a voltage threshold as well as a MW threshold to focus the efforts on meaningful impacts to their Planning Assessments while at the same time minimizing the burden on entities required to provide the data.

MOD-032 (SPIDERWG SAR)

The SRC sees significant value in ensuring that PCs and Transmission Planners (TPs) have the DER data contemplated by the SAR; as such, the SRC supports the proposed changes to MOD-032-1.

It is important from a reliability perspective for the PC and TP to have information regarding DERs with the potential to impact reliable operation of the BPS to accurately model load and generation. As is recognized under current NERC standards, NERC requirements are not limited to managing BES

facilities only; e.g., loads connected at 100 kV or above and resources equal or greater than 75 MVA. As identified in the FERC/NERC Staff Report in the September 8, 2011 Blackout report, an underlying cause of the event was “not identifying and studying the impact on Bulk-Power System (BPS) reliability of sub-100 kV facilities in planning and operations.” Therefore, to the extent a non-BES facility has the ability to impact the reliability of the BES, NERC has the ability to require it be identified and studied. This is already the case in existing NERC standards, e.g., TOP-001-5, Transmission Operations, requirement R10, Part 10.3:

“Each Transmission Operator shall perform the following for determining System Operating Limit (SOL) exceedances within its Transmission Operator Area: Monitor non-BES facilities within its Transmission Operator Area identified as necessary by the Transmission Operator.”

The reliability of the BPS would be improved with the modeling of DER generation (e.g., as equivalents on a substation low voltage bus) separate from the distribution load, which ultimately leads to modifying MOD-032’s data collection requirements. As the amount of DERs increases on a system, netting generation from load leads to modeling inaccuracies and the potential of masking performance issues that would not otherwise be taken into consideration, such as times when the DERs are not able to generate; netting generation from load is not a preferred method. Modeling DERs explicitly as generator equivalents and separating them from load gives an opportunity to enhance case fidelity, improve Planning Assessments and mitigate overall system impact.

The SRC recognizes that the LSE function is retired, however, the SRC notes that simply replacing Load Serving Entity (LSE) function with Distribution Provider (DP) function may not be the optimum solution. Accordingly, while the information contemplated in the SAR would no doubt benefit PCs, that information may be incomplete due to gaps in the data collection process. The SRC recommends the Standard Drafting Team spend time to review the reliability impact of the LSE tasks as they exist before a blanket DP replacement. The SRC also recommends that this effort be followed by the identification of information and data availability gaps for DERs and the provision of recommendations or guidance to resolve the identified gaps.

The SRC believes the Standard Drafting Team should also consider assigning the responsibility of DER data collection to the Transmission Owner (TO) rather than the PC or TP. The TO has direct contact with DPs and is in a better position in terms of visibility to account for what is being connected at the distribution level and provide a suitable, aggregated modeling information to the PC and TP for inclusion in system impact studies. The table in Attachment 1 should include references to aggregate DER, categorized by intermittent resources and dispatchable resources, in the steady-state and dynamics columns and be assigned to the DP and TO. Ideally, the DP provides the data to the TO and the TO includes that data in their submission to the TP/PC. DPs must also provide their total system load absent any DER modification, unless approved to be netted by the TP/PC. The DPs and TOs must timely provide the data to meet the annual model build schedule established by the TP/PC.

The SRC also asks that the SAR scope specifically states that requirements will be created for data needed from the appropriate functional entities, as implied by the box checked in the SAR form: “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.”

[The IRC SRC includes the following entities: CAISO, ERCOT, IESO, MISO, ISO-NE, NYISO, PJM and SPP.]

Likes 0	
Dislikes 0	

Response

Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

MOD-032 SAR

Data collection requirements should be kept within practical reason. DP's cannot be expected to collect detailed information for every rooftop solar installation on their system. Considering the broad scope of DER's, the standard should set a reasonable expectation for the level of information required to be collected per Attachment 1 of the standard.

DER data collection and modeling requirements should consider the existing processes of all PC's. For example, there are DERs registered with ERCOT, typically U-DER, where the DER owners are required to provide DER mapping and modeling data directly to ERCOT, and ERCOT is responsible for mapping and modeling these types of DERs in the operations and planning models. ERCOT is provided residential and small commercial DER, typically R-DER, in aggregate for mapping to the network operations model. Any deviation from the existing ERCOT processes may cause more confusion and inefficiency.

TPL-001 SAR

Given the broad scope of the topic of DER, the standard language should set a reasonable expectation for the level of detail required in simulation regarding DER's.

Because of the nature of DER, it is possible for a single distribution bus to connect U-DER installations with different inverters, legacy IEEE standards, and protective settings. R-DER may also differ and may require aggregations by inverters with similar performance characteristics. During the modeling process these installations may be aggregated into a single unit modeled at the bus in order to avoid having many different generator models on a single bus. A requirement to explicitly simulate the protection and behavior of all these inverters would require a much greater modeling burden.

Given the broad scope of the topic of DER, the standard language should set a reasonable expectation for stability performance criteria. Inverter based generation, and especially DER's, are prone to tripping for many transmission level events on the system. A requirement to mitigate for every observed inverter based trip may be impractical for Transmission Planners to execute.

Texas's Substantive Rules require highly sensitive DER tripping standards for Voltage and Frequency protection. Transmission level faults are likely to cause DER tripping in the area. There should not be a requirement to mitigate every DER trip that is observed, even if it is for a P1 event.

Likes 0	
Dislikes 0	

Response

Matthew Jaramilla - Salt River Project - NA - Not Applicable - WECC

Answer	Yes
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Buswell - VELCO -Vermont Electric Power Company, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ramneek Dimen - Seattle City Light - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	

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	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darcy O'Connell - California ISO - 2	
Answer	
Document Name	
Comment	
CAISO agrees with comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee (SRC)	

Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the SARs drafting team to consider, if desired.	
Matthew Jaramilla - Salt River Project - NA - Not Applicable - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3, Group Name Eversource Group	
Answer	
Document Name	
Comment	

Suggest changing the **SAR titled, 'TPL-001-5.1 Transmission System Planning Performance Requirements' (dated 12/15/2021)** to TPL-001-5.1 SPIDERWG SAR since this currently shares the same SAR title as the TPL-001-5.1 IRPWG SAR.

Since not all DER is inverter-based, suggest changing:

· The SDT can consider adding asynchronous generator related devices like inverter, plant controller, etc.

to:

· The SDT can consider adding synchronous generator over-excitation limiters (OELs), under-excitation limiters (UELs) and asynchronous generator related devices like inverter, plant controller, etc.

Suggest changing the **SAR titled, 'TPL-001-5.1 Transmission System Planning Performance Requirements' (dated 12/16/2021)** to TPL-001-5.1 IRPWG SAR since this currently shares the same SAR title as the TPL-001-5.1 SPIDERWG SAR.

Since the impacts to the BES are coming from high/low-voltage connected inverter-based utility-scale inverter-based resources, suggest changing:

- Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources

to:

- Many areas of the North American bulk power system (BPS) continue to experience an increase in directly and indirectly BPS-connected, utility scale inverter-based resources.

Suggest changing:

- Not included in this list are power plant controllers and inverter controls, which often dominate the dynamic response of IBRs.

to:

- Not included in this list are power plant controllers, inverter controls, limiters, etc., which often dominate the dynamic response of IBRs and can also be applicable to synchronous generators.

SAR "MOD-032-1 Data for Power System Modeling and Analysis"

Suggest changing:

- that are necessary to support the development of accurate interconnection-wide models

to:

- that are necessary to support the development of accurate regional and interconnection-wide models

Suggest there should be modifications to the short circuit column of Attachment 1 because while #1 already states "all applicable elements" in the steady-state column, that does not mean we have necessary information related to positive, negative, and zero sequence data. In areas with low short-circuit margins, the impact of DER can make/break the system.

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC) 2022-02 SAR

Answer	
Document Name	

Comment

The SRC believes the PC and TP need to have information on all DERs impacting the BPS, as load and generation have distinct impacts on the accuracy of the study results. A standard addressing modeling should not limit what information may be required to accurately model the BES. Nor should it be restricted to modeling only data tied to the BES Definition thresholds – as the electrical properties of the grid are not limited to the BES Definition. In load forecasts today, the planning models are not limited to modeling only loads above 100KV and resources above 75 MVA. The same should be true for DERs. Due to the growing DER impact, the potential significant impact of DERs on the system, and the "invisibility" of these resources to the PCs and TPs, this project needs to find a way for PCs and TPs to acquire and model DERs separate from load, even though they fall outside the definition of BES.

The SRC recognizes that too much data is cumbersome to collect and manage, and can be a hindrance to all involved. Thus, the SRC proposes the Standard Drafting Team avoid a granular approach to data collection, which may contemplate zero-defect compliance, but instead focus on a risk-based approach that would result in efficient and effective collection of large DER and aggregated DER modeling data, in light of the use of the data for

planning models. Planning models are forward looking (versus real-time) using existing system information and forecasts, so awareness and knowledge of the current system is important, but perfect knowledge is not necessary.

In addition, the SRC acknowledges that there are challenges associated with collecting distribution data, so due consideration should be given to Responsible Entities to establish screening criteria and/or to aggregate data to allow for modeling efficiency such that the technical benefits received are commensurate with the cost and effort of obtaining the data. A granular approach to modeling data would only serve to "clutter" the model, making it impractical and resource-intensive to maintain.

The fundamental issues of a modeling framework, risk-based performance standards, and appropriate enforcement for low-risk issues must be clearly addressed and implemented for industry and regulators to avoid being pulled into the meticulous examination of each piece of data provided.

Finally, the SRC recommends the consistent use of "inverter-based resource" by the SARs and the Standard Drafting Team rather than asynchronous resource.

[The IRC SRC includes the following entities: CAISO, ERCOT, IESO, MISO, ISO-NE, NYISO, PJM and SPP.]

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	
Document Name	

Comment

The SPIDERWG SAR only states that DERs should be modeled if data is available, and not all DERs in the "Requested Information Section". Therefore, the statement, "*In general, the impact of DERs on the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or justification*", should be included in the standard in addition to the changes.

I do not agree with tripping DERs in R3.3.1.1 and R4.3.1.2. I agree that DERs should be monitored after transmission and/or generators fault, but not tripped. Additionally, in R4.1.1 and R4.1.2, I do not agree DERs should be included in the stability performance criteria of the TPL. We, as planners, will be required to make correction action plans based on our studies, but we are not the owners of the DERs.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

SPP recommends that the drafting team take into consideration coordinating with the Project 2021-06 Modifications to IRO-010 and TOP-003 (drafting team) and their efforts in reference to their IRO-010 SAR. We understand that IRO-010 doesn't meet the scope of this project. However, at this point, our concern is that both standards are used in the process for data acquisition and doesn't have the foundational language to enable an entity to obtain the pertinent data needed to perform accurate studies (for example- planning and/or ops modeling data) to maintain the reliability of the grid. From our perspective, there is an opportunity for both drafting teams to work together and learn about the needs of both the requesting and sharing entities perspective in reference to data acquisition as well as ensuring the appropriate data exchange is accomplished with the common goal of maintaining the reliability of the grid.

Furthermore, SPP recommends that the drafting team take into consideration including the EMT (Electromagnetic Transient Studies) data into the scope of the MOD-032 efforts. Again, we understand that this effort is not currently included into the scope of the MOD-032 SAR. However, this is a form of data collection that is applicable to a study that's more granular than the dynamic study listed in the attachment 1 of the MOD-032 Standard.

SPP is concerned that entities like the TP and PC cannot obtain modeling data such as phase lock loop parameters to conduct appropriate inverter instability screening studies and EMT models to perform EMT studies, for example. Further, there are other concerns as follows:

•Spurious spikes in electrical quantities in positive sequence RMS (Root-Mean-Square) simulations can occur at any bus. This is caused by sudden changes in inverter terminal voltage phase angle due to network bus voltages being algebraic variables in the RMS simulation instead of differential equations that offer the true response. Without EMT studies, these disturbances may not be recognized.

•Dynamics models do not include the real-code behavior of inverter-based resources and often involve engineering judgment based on controller block diagrams used in representing the actual performance of these complex power electronic resources. Gaps exists in identifying the exact thresholds at which inverter and plant protection would activate that could be dependent on knowledge of the real code within the control systems.

Additionally, SPP's interpretation is that the MOD-032 Standard (attachment 1) does not give entities, like the TP and PC, the complete support to obtain this type of modeling data. As an example, our organization has requested the phase lock loop data from the Interconnection Customers and the OEMs (Original Equipment Manufacturer) only to have our request denied due to "proprietary legalities". At this point, SPP is not confident the GO will provide this modeling data to help ensure quality results from the study.

As for the SPIDERWG TPL-001-5 SAR, SPP recommends that the drafting team takes into consideration adding more clarity pertaining to the resources that the DER definition is applicable to. From our perspective, it is unclear about the DER's definitional stance in reference to the inclusion or exclusion of Demand Response. For example, the SPIDERWG Terms and Definition Document (notes: Loads and Demand Response do not produce electric power and are therefore not included in the definition of DER). Does this note have merit? We have a concern that the inclusion\exclusion of Demand Response data will impact the model's accuracy when performing planning assessments. We would hope to have a clear direction of how to appropriately handle this data so we provide quality planning assessments.

Furthermore, we would recommend that drafting team take into consideration of adding clarity in reference to the inclusion\exclusion of R-DERs and U-DER in the applicability of the DER definition. We understand that the DER Parameterization guideline discusses the R-DERs and U-DERs. However, our concern is basically the same for the R-DERs and U-DERs as mentioned in the previous paragraph.

Likes 0	
Dislikes 0	

Response

Scott Brame - North Carolina Electric Membership Corporation - 3,4,5 - SERC

Answer	
Document Name	

Comment

NCEMC fully supports the comments submitted by the North American Generator Forum for this NERC Project.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
No additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The existing MOD-032-1 standard already allows PCs/TPs to request the DER information contemplated in the SAR. Modifications to the standards should be focused on obtaining modeling data and not dictate what must be included in the model or how assessments are performed. That should be left up to the PC/TP.

In the interest of standardization of general process flow across all the NERC standards, the NAGF suggests that language/requirements be added to MOD-032, similar to IRO-010-3 R2 and TOP-003-4 R3 and R4, which requires the PC and TP to ***distribute*** *its data specification to entities that are required to submit data to be used in the models.*

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - Florida Municipal Power Agency - 1,3,4,5,6 - SERC, Group Name FMPA and members

Answer	
Document Name	

Comment

Attachment 1 for MOD-032 is very high level and allows the PC/TP discretion to request DER data already. The proposed changes to MOD-032 only increase industry awareness and establish a minimum bar. There are regions where the current levels of penetration are far too low for any real impact. SPIDERWG SAR acknowledges this by allowing for the SDT to establish thresholds for when DER may be required to be included. If any changes are made to Attachment 1 to MOD-032, such thresholds should be coordinated. That is, if for example TPL-001 language is drafted that states that DER need to be explicitly modeled only when above 10% penetration, then data should only be mandatory from MOD-032 for that same level.

Other issues presently in MOD-032 that ought to be cleaned up if Attachment 1 is modified.

1) Attachment 1 still refers to LSE as does the overall standard. We are aware this reference was previously intended to be removed.

2) Positive sequence branch impedance / shunt admittance data really ought to be listed in steady state, and then negative and zero added in short circuit.

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5,6

Answer	
Document Name	

Comment

N/A

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

FirstEnergy - while supporting the scope in the SARS - supports EEI's request for clarification and changes to the three SARS.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offers comments on each of the individual SARs below:

TPL-001-5.1 IRPWG SAR Comments

EEI could support this SAR if the following changes were incorporated within the next version of the SAR.

- **Industry Need:** As noted in our response to question 1, references to the Bulk Power System (BPS) should be changed to Bulk Electric System (BES). Often, responsible entities find it difficult, and in some cases impossible, to obtain data from non-BES resources because they are not registered and do not have any regulatory obligation to provide data when requested. For this reason, we do not support the statement in paragraph 3 which requires the TPL-001-5.1 Reliability Standard be modified to address all “BPS-connected inverter-based resources”, and request the scope be limited to all BES inverter-based resources.
- **Purpose or Goal:** BPS-connected inverter-based resources should be changed to BES inverter-based resources.
- **Project Scope:** EEI supports making the term “GSU transformer” suitable for all generation types and suggests that the SDT consider an approach similar to what was done to address this issue in PRC-024-3 (see main power transformer definition). Additionally, BPS-connected inverter-based resources should be changed to BES inverter-based resources. We also support the proposed changes to 4.1.1 and 4.1.2. Lastly, we do not agree that entities should be required to maintain lists of all devices that might impact the study area inclusive of BPS-connected inverter-based resource technologies. This represents a substantial burden that goes beyond what entities can reliably collect.
- **Detailed Description:** EEI supports the detailed description provide in the SAR which we note was “copied verbatim from the IRPTF white paper that was approved by the NERC PC” and does not specify BPS-connected inverter-based resources.

TPL-001-5.1 SPIDERWG SAR Comments

EEI recognizes the importance of accurately planning transmission system performance and the impacts of Inverter-based resources, including DERs. However, there are substantial issues and challenges for the industry because many of these newer resources fall outside of NERC's jurisdiction or the ability of responsible entities to collect the needed data. Nevertheless, we could support the proposed SAR with the following changes:

- **Industry Need:** Footnote 1 should be corrected by replacing BPS with BES. EEI notes that the Purpose statement in TPL-001-5.1 states the scope of this Reliability Standard as: "Establish Transmission system planning performance requirements within the planning horizon to develop a **Bulk Electric System (BES)** that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."
- **Project Scope:** EEI offers the following changes to the SAR Project Scope:
    - **Item a**: identifies Requirement 2, subparts 2.1 and 2.2 as using the phrase "System peak Load" but the subparts that use this term include: 2.1.1, 2.2.1 and 2.4.1. The SAR scope should be changed to reflect the correct subparts where the phrase is used.
    - **Item b:** EEI does not support the language because it does not clarify the concern contained in the reference SPIDERWG whitepaper or provide clear language that an SDT could act upon.

1. The SAR states that the SDT should "include tripping of DER if data and models are available", however, there are no methods contained with the any Reliability Standard that would define how PCs or TPs could collect this data. While we understand that some transmission tariffs may provide viable methods for collecting some of this data from Transmission Service Providers (TSP), this is tariff dependent and cannot be universally relied upon. Therefore, it is unclear how these two entities would have sufficient data to perform an effective planning study in most regions.
2. The second sentence in Item b states that the SDT should consider whether a threshold needs to be established, however, the SAR does not clarify what threshold should be considered. In the whitepaper, it states that "no specific threshold for DER modeling is suggested, each entity should keep track of DER to make such determinations". Given the whitepaper is the basis for the SAR and "no specific threshold is suggested" we suggest this statement be removed.

- **Item c:** The language contained in Requirement R4, subparts 4.1.1 and 4.1.2 should be clarified to consider Inverter-based resources. Relative to DERs, these resources are part of the distribution system and currently, there are no provision that would ensure that PCs or TPs have any ability through the NERC Reliability Standards to collect sufficient data to conduct the planning studies envisioned. Even obligating DPs to collect this data is unlikely to solve the problem since many of the DER owners have no regulatory obligation to provide this data to the DPs.
- **Item d:** EEI agrees that the automatic performance of Inverter-based resources, including DERs, is important to accurately develop planning performance requirements for the BES, however, the industry's ability to accurately accomplish this is tied to their ability to gather accurate data on DERs, which are often outside of the registration criteria. For this reason, we suggest that the language be tempered to ensure that entities are only held responsible for the data they gather. To address this concern, EEI suggests a more practical approach is to use composite load models based on known nameplate data using engineering judgement.

MOD-032-1 (SPIDERWG SAR) Comments

EEI's position on this SAR it the same as the last time it was posted for comment. EEI does not support the proposed SAR as currently written, however, we support adding the DP function to MOD-032 to address a potential reliability gap related to data that can only be effectively collected by the DP, since the deregistration of the LSE. For this reason, we would support a limited SAR that only addresses this issue. Once this is done, we believe the existing MOD-032 Reliability Standard should provide adequate protections to ensure that the Planning Coordinators (PC) and Transmission Planners (TP) are able to collect data necessary to account for distributed energy resources (DER) to develop planning models in a manner sufficient to support the reliable operation of the interconnected transmission system under their purview.

Additionally, the SAR still lacks supporting technical justifications, such as a white papers, describing what if any reliability gap exists. For these reasons, we ask that the proposed SAR not be approved. We support the good work being done by the SPIDER Working Group (SPIDERWG), including the development of a draft Reliability Guideline that have been issued for industry review and comment for the collection of DER data for modeling transmission planning studies. We additionally recommend the SPIDERWG develop Implementation Guidance to support the existing MOD-032-1 Reliability Standard and associated Reliability Guideline. Additionally, we would support a NERC initiative to evaluate the effectiveness of the above referenced Reliability Guideline (see Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies dated Sept. 2020) to determine if there are reliability gaps or issues with the PCs and TPs obtaining the necessary modeling data needed for grid reliability. As noted above, EEI encourages the SPIDERWG to develop Implementation Guidance to provide clear examples and approaches to better inform planners on

possible methods to ensure MOD-032-1, as currently written and approved, more effectively addresses the collection of specific DER data as well as provides guidance on how to ensure consistency in DER modeling data requirements and reporting procedures, particularly among adjoining PCs.

In addition to the above comments on this SAR, we offer the following additional concerns:

1. EEI disagrees with Item 3 contained within the Industry Need statement. There is no need to "review any additional gaps in DER data collection with the de-registration of LSE." Such a review is inconsistent with the FERC order (153 FERC ¶ 61,024) approving the removal of LSEs from the functional registration. Notably, RCs, BAs, and REs and other affected entities that need the information from LSEs had no concerns if LSEs were no longer registered. The working group should take notice of the FERC conclusions and findings in this order. EEI also disagrees with the following statement in this section: "As the penetration of distributed energy resources (DERs) **continues to increase across the North American bulk power system (BPS)**, it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES." A more accurate statement would be: As the penetration of distributed energy resources (DERs) continues to increase **across the many distribution systems**, it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES.
2. EEI disagrees with the Purpose and Goal statement. Specifically, it is not clear what gaps within the currently approved MOD-032-1 beyond the need to add the DP function, exist.
3. EEI does not support the Project Scope as defined in the SAR.
    i. Attachment 1 – Data Reporting Requirements within MOD-032-1 do not need to be updated. Steady-State (Item 2 and Item 9), and Dynamics (Item 10) provide sufficient flexibility for PCs and TPs to ensure that DER data is collected. We further note that these items provide sufficient latitude in what is collected. "Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]".
    ii. EEI does not see a need to define the term Distributed Energy Resource (DER) but does not oppose a drafting team evaluating it and offering the industry a proposed definition.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 5,6

Answer	
Document Name	

Comment

N/A

Kimberly Turco on behalf of Constellation Segments 5, 6

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends the SAR team consider addition of any IBR-related criteria for short circuit analysis.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	
The SARs (and ultimately any Standards drafted or revised as a result of the SARs) should not use the term Bulk Power System (BPS). The SARs should adhere to the term Bulk Electric System (BES), as the BES is what NERC Standards apply to. Compliance with NERC Requirements is enforced on the BES. BES is also extensively defined by NERC and well understood by registered entities. The term BPS is too vague and its use in the SARs and any subsequent Standards will lead to confusion and a general lack of clarity regarding the applicability of assets and Facilities. DERs are generally connected to the Low and Medium-voltage distribution voltages and many of them may be insignificant for BES. Hence, the SARs should include a requirement to properly define DER that shall be included as an Inclusion in the BES Definition to be providers of data as per the requirements of NERC Standards. This will ensure that DERs are required to provide that data.	
Likes 0	

Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
• Time and cost requirements for the submitted SARs appear to be under stated. Adding glossary terms, as the SAR suggests, and modifying standard requirements would almost certainly lead to more significant coordination efforts with other standards and definitions. • There also needs to be consideration to have region-specific efforts to address DER penetration to account for the system differences. • GTC supports the comments submitted by Southern Company.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	
Document Name	
Comment	
We offer the following additional (a-f) comments for consideration by the SAR drafting team: a) We do not support a SAR that dictates overly prescriptive data requirements that the TP/PC must request from the DP, as the existing MOD-032 standard already allows PCs/TPs to request the type of information contemplated in the SAR; b) Any modifications to the standard should be focused on obtaining modeling data and should not dictate what must be included in the model and how assessments are performed; c) Any modifications to the standard related to DER should recognize that a small quantity of DERs could have no impact on BES studies, especially for low penetration regions, and thus could be netted out with load with no impact to reliability. That determination should be left up to the individual TP/PC; d) Cost impact may not be minimal depending on the scope of data being requested; e) We endorse the comments developed by EEI; f) We support the comments submitted by Georgia Transmission Corporation.	
Likes 0	
Dislikes 0	
Response	

Ramneek Dimen - Seattle City Light - 1 - WECC	
Answer	
Document Name	
Comment	
Seattle City Light is largely in agreement with the direction of this SAR, and we understand the desire to include DERs in modelling efforts in the continued pursuit towards a secure and reliable grid. That being said, greater clarification in the Standard is desired around minimum penetration levels of DERs on the system and minimum capacity requirements. While we see the importance of this effort, without setting thresholds, as we have on the generation side, entities will be putting a lot of time, effort, and resources into modelling DER related data that may have little to no impact on the reliability of the grid, and whether there will be any deference given to region specific needs.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	
Document Name	
Comment	
Not at this time.	
Likes 0	
Dislikes 0	
Response	

Unofficial Nomination Form

Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, March 02, 2022.** 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 TPL-001-5.1 and MOD-032-1

Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward.

The NERC Inverter-Based Resource Performance Task Force (IRPTF)[1] undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020.[2] Based on the outcome of the review, it was determined that the TPL-001-4/5[3] needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised.

As the penetration of distributed energy resources (DERs) continues to increase across the North American bulk power system (BPS), it is necessary to account for the potential impacts of DERs on

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).

[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf

[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

reliability in the planning, operation, and design of the BES. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs). MOD-032-1 addresses the gathering of modeling data to perform planning assessments but the standard currently has no specific reference to DER data. This SAR proposes to update MOD-032-1 to: (1) include "data requirements and reporting procedures"[4] for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, and (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.

Standards affected: TPL-001-5.1 and MOD-032-1

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 Transmission Planning, Modeling, and are familiar with NERC Standards TPL-001 and MOD-032.

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):	

[4] See Requirement R1 of MOD-032-1, which requires each TP and PC to develop data requirements and reporting procedures for the collection of modeling data used for the development of models for each PC footprint.

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[5] 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	

[5] 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:	

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1

Nomination Period Open through March 02, 2022

Now Available

Nominations are being sought for Standard Authorization Request (SAR) drafting team members through **8 p.m. Eastern, Wednesday, March 02, 2022**.

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.

This team will meet regularly, up to twice a week on conference calls, with face-to-face meetings scheduled as the members' schedule and the pandemic allow, to meet the agreed-upon timeline the drafting team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous drafting 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 April 2022. 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 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 observer list" in the Description Box.

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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:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/16/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Allen Schriver, NextEra Energy (NERC IRPWG Chair) Julia Matevosyan, ERCOT (NERC IRPWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC Inverter-Based Resource Performance Working Group (IRPWG)		
Telephone:	Al – 561-904-3234 Julia – 512-994-7914	Email:	Allen.Schriver@fpl.com Julia.Matevosyan@ercot.com

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

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

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward.

Requested information
The NERC Inverter-Based Resource Performance Task Force (IRPTF)[1] undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020.[2] The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. The white paper recommended modifications to seven standards, and IRPWG presented four SARs to the NERC Reliability and Security Technical Committee (RSTC) in June 2020 that addressed the deficiencies identified in six of the seven standards. Based on the outcome of the review, it was determined that the TPL-001-4/5[3] needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The language used in the white paper regarding "the next time the standard is revised" was based on the understanding that the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was developing a SAR and that the recommended modifications to TPL-001-5 from IRPWG could be included in the SPIDERWG SAR. The combined SAR was presented to the NERC RSTC at their March 2021 meeting and was rejected. The overarching comments received were with regards to the DER-related issues and a comment was made that the recommendations pertaining to BPS-connected inverter-based resources were not the primary focus of concern. Therefore, IRPWG presents this SAR to move the effort forward regarding specifically BPS-connected inverter-based resources. This SAR does not include any modification to TPL-001-5 regarding the inclusion of distributed energy resources (DERs). IRPWG believes that industry needs to be proactive in addressing standards gaps, particularly, where lack of clarity and confusion may lead to studies not adequately capturing possible BPS reliability issues. As the North American BPS continues to experience rising penetration levels of BPS-connected inverter-based resources and is likely to do so into the foreseeable future, these changes are critical for overall BPS reliability and industry efforts to reliably integrate these resources.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR revises requirements within the TPL-001-5 standard to provide clarity and consistency for how BPS-connected inverter-based resources are considered, modeled, and studied in planning assessments. The proposed revisions to TPL-001-5 will ensure industry is effectively and efficiently conducting planning assessments and that the requirements are equally suitable for inverter-based resources as they are for synchronous generation.

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).
[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf
[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

Requested information
Project Scope (Define the parameters of the proposed project):
As described in further detail below, the scope of this project includes consideration of the following revisions to TPL-001-5.1: • Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term "GSU transformer" suitable for all generation types since it introduces confusion for BPS-connected inverter-based resources • Modify Requirements 4.1.1 and 4.1.2 regarding the use of the term "pulls out of synchronism," which is only applicable for synchronous generator technologies and is not suitable for BPS-connected inverter-based resources • Modify Requirement 4.3.2 so that the list of devices that impact the study area are inclusive of BPS-connected inverter-based resource technologies •
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The following detailed description is copied verbatim from the IRPTF white paper that was approved by the NERC PC: 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 main power transformer (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

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

Requested information
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.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impacts for the proposed changes to TPL-001-5 are expected to be minimal. The changes being proposed are clarifications that will bring consistency and effectiveness industry related to how planning assessments are conducted and how planning engineers set up and conduct those assessments.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will impact Transmission System Planning Assessments, not any specific BES facilities.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinators, Transmission Planners, and Generator Owners of inverter-based resources

Requested information
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.
This SAR is an outcome of the white paper produced by the NERC IRPTF and approved by the NERC PC, which can be found here: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf The SAR is a follow-on to the recommendation contained within the white paper, developed by the NERC IRPWG under the NERC RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
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 NERC IRPWG (previously IRPTF) has published multiple technical reference documents, white papers, and reliability guidelines related to the performance, modeling, and studies of BPS-connected inverter-based resources. These technical materials are used widely by industry and have provided significant value for improving planning practices. However, those efforts do not address the larger issue related to the TPL-001 standards language being written predominantly for synchronous generation technology and not adequately considering or clarifying how the requirements relate to BPS-connected inverter-based resource technologies.

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.

[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	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

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

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised

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

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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:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/16/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Allen Schriver, NextEra Energy (NERC IRPWG Chair) Julia Matevosyan, ERCOT (NERC IRPWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC Inverter-Based Resource Performance Working Group (IRPWG)		
Telephone:	Al – 561-904-3234 Julia – 512-994-7914	Email:	Allen.Schriver@fpl.com Julia.Matevosyan@ercot.com

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

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

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward.

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Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR revises requirements within the TPL-001-5 standard to provide clarity and consistency for how BPS-connected inverter-based resources are considered, modeled, and studied in planning assessments. The proposed revisions to TPL-001-5 will ensure industry is effectively and efficiently conducting planning assessments and that the requirements are equally suitable for inverter-based resources as they are for synchronous generation.

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).
[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf
[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

Requested information
Project Scope (Define the parameters of the proposed project):
As described in further detail below, the scope of this project includes consideration of the following revisions to TPL-001-5.1: • Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term "GSU transformer" suitable for all generation types since it introduces confusion for BPS-connected inverter-based resources • Modify Requirements 4.1.1 and 4.1.2 regarding the use of the term "pulls out of synchronism," which is only applicable for synchronous generator technologies and is not suitable for BPS-connected inverter-based resources • Modify Requirement 4.3.2 so that the list of devices that impact the study area are inclusive of BPS-connected inverter-based resource technologies •
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The following detailed description is copied verbatim from the IRPTF white paper that was approved by the NERC PC: 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 main power transformer (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

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Requested information
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.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impacts for the proposed changes to TPL-001-5 are expected to be minimal. The changes being proposed are clarifications that will bring consistency and effectiveness industry related to how planning assessments are conducted and how planning engineers set up and conduct those assessments.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will impact Transmission System Planning Assessments, not any specific BES facilities.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinators, Transmission Planners, and Generator Owners of inverter-based resources

Requested information
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.
This SAR is an outcome of the white paper produced by the NERC IRPTF and approved by the NERC PC, which can be found here: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf The SAR is a follow-on to the recommendation contained within the white paper, developed by the NERC IRPWG under the NERC RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
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 NERC IRPWG (previously IRPTF) has published multiple technical reference documents, white papers, and reliability guidelines related to the performance, modeling, and studies of BPS-connected inverter-based resources. These technical materials are used widely by industry and have provided significant value for improving planning practices. However, those efforts do not address the larger issue related to the TPL-001 standards language being written predominantly for synchronous generation technology and not adequately considering or clarifying how the requirements relate to BPS-connected inverter-based resource technologies.

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.

[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	
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

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

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised

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

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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:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu, MISO (NERC SPIDERWG Chair) Bill Quaintance, Duke Energy Progress (NERC SPIDERWG Vice-Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC System Planning Impacts from DERs Working Group (SPIDERWG)		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.com

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

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

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

Many distribution systems connected both directly and indirectly to the North American BES are experiencing increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-5.1[1] was developed under a paradigm of predominantly BPS-connected generation, particularly synchronous generation, when penetrations of DERs were significantly lower than current and future projections.

Considering current trends, the NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR:

[1] The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BES planning.

Requested information

- SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here)

This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper.

TPL-001-5.1 does not currently require Planning Coordinators and Transmission Planners to complete Planning Assessments with adequate representation of the dynamic behavior of DERs. As the penetration of DERs increases, and based on the DER data and models available, Planning Assessments should include DERs that can potentially impact Transmission System performance assessment. NERC's "Lesson Learned: Single Phase Fault Precipitates Loss of Generation and Load", evaluating a 2019 frequency event in Southern England exacerbated by the unexpected reduction of 725 MW of IBR output and the unexpected loss of 350 MW of DER, highlights the critical importance of accurate Transmission System Planning Assessments.[2] In July 2020, a significant quantity of solar PV facilities across a large geographic area in Southern CA reduced about 1000 MW output due to a disturbance on the bulk power system[3]. Subsequent event analysis revealed that it was the consequence of momentary cessation and slow recovery of power. Standards enhancement has been one of the recommendations after the event analysis to ensure reliable operation of the bulk power system.

In general, the impact of DERs on the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or justification.

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

The purpose of this SAR is to revise requirements to provide clarity or, in some cases, expand the scope of requirements when considering the performance of DERs to ensure the accuracy of Transmission System Planning Assessments.

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

As identified by SPIDERWG, revision to the following sections of TPL-001-5.1 should be considered to ensure the accuracy of Transmission System Planning Assessments:

a. R2.1, R2.2, and R2.4, the use of phrase "System peak Load"
b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data and models are available. The SDT can consider whether a threshold needs to be established.

[2] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201001_Single_Phase_Fault_Precipitates_Loss_of_Generation_and_Load.pdf
[3] https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. d. R4.3.2, the list of dynamic control devices should include DER so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses. e. Assuming that revisions to the MOD-032 standard ensure that DER model data is available, modification to the TPL-001 standard should give consideration to potential exclusions of explicit DER modeling based on technical rationale.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
A detailed description of each Project Scope item is given below: a. R2.1 and R2.2, the use of phrase "System peak Load" With increased penetration of DER, the load that transmission system supplies is the net load (net load = gross load – DER output) as seen at the T-D interface, which might reach its peak during operating conditions that are not at the peak gross load hour. As such, there is a need for individual TPs to be required to document and define their peak load conditions (e.g., gross or net) in their assessments. The SDT should consider adding the terms "Gross Load" and "Net Load" to the NERC Glossary of Terms and updating the term "System peak Load" in the standard to "System peak net Load". In addition, a high gross load hour may be the most stressed load driven condition for contingencies that may trip large amounts of DER. High system peak gross load may be studied as additional scenarios as required by current standard under R2.1.3. b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data is available. The SDT can consider whether a threshold needs to be established. The terms "generators" in Sub-requirements 3.3.1.1 and 4.3.1.2 should be clarified. DERs that are explicitly modeled as generators should be tripped where simulations show bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to consider inclusion in the assessment any assumptions made in estimating DER bus voltage.

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

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. For example, the language referring to "pulls out of synchronism" is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). However, large amounts of asynchronous DER tripping on low/high voltage/frequency conditions can also adversely affect BES performance and may pose a risk to system instability for conditions such as cascading, voltage instability, or uncontrolled islanding if not properly studied and identified ahead of real-time operations. It is recommended to expand the stability performance criteria to include both synchronous and asynchronous generation. d. R4.3.2, the standard should recognize that the list of dynamic control devices should consider the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) in stability analyses. The SDT can consider adding asynchronous generator related devices like inverter, plant controller, etc.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Although the cost impact is unknown, costs to Planning Coordinators and Transmission Planners will increase as Transmission System Planning Assessments reflect additional dynamic components and controls. It is anticipated that this cost will vary depending on training, tools, scenario development, and other factors in each Planning Coordinators and Transmission Planners' area.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will primarily impact Transmission System Planning Assessments, not any specific BES facilities, although as individual IBRs continue to increase in size (e.g. 14MW wind turbines), there may be some impact in the near future.
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 Coordinators and Transmission Planners, i.e. the applicable entities for this standard. Additionally, Distribution Providers, Generator Owners, and DER aggregators participating in markets- i.e. not an applicable entity to this standard, would be useful to include.

Requested information
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.
This SAR is the outcome of the following white paper that was developed by the NERC technical sub-group under the RSTC. • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) Deliverables, and the key findings and recommendations contained within, were thoroughly reviewed and approved by the RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
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.
Among all the issues identified in the NERC SPIDERWG white paper, the ones included in this SAR cannot be addressed by any alternatives. Standard language change will ensure DER impacts being considered appropriately. NERC SPIDERWG will prepare a Reliability Guideline to address the rest of the findings from their white paper.

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.

[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.

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

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

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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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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:	TPL-001-5.1 Transmission System Planning Performance Requirements		
Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu, MISO (NERC SPIDERWG Chair) Bill Quaintance, Duke Energy Progress (NERC SPIDERWG Vice-Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	NERC System Planning Impacts from DERs Working Group (SPIDERWG)		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.com

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

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

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

Many distribution systems connected both directly and indirectly ~~areas of~~ to the North American BES are experiencing increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-5.1[1] was developed under a paradigm of predominantly BPS-connected generation, particularly synchronous generation, when penetrations of DERs were significantly lower than current and future projections.

Considering current trends, the NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR:

[1] The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BES~~BPS~~ planning.

Requested information
• SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper. TPL-001-5.1 does not currently require Planning Coordinators and Transmission Planners to complete Planning Assessments with adequate representation of the dynamic behavior of DERs. As the penetration of DERs increases, and based on the DER data and models available, Planning Assessments should include DERs that can potentially impact Transmission System performance assessment. NERC's "Lesson Learned: Single Phase Fault Precipitates Loss of Generation and Load", evaluating a 2019 frequency event in Southern England exacerbated by the unexpected reduction of 725 MW of IBR output and the unexpected loss of 350 MW of DER, highlights the critical importance of accurate Transmission System Planning Assessments.[2] In July 2020, a significant quantity of solar PV facilities across a large geographic area in Southern CA reduced about 1000 MW output due to a disturbance on the bulk power system[3]. Subsequent event analysis revealed that it was the consequence of momentary cessation and slow recovery of power. Standards enhancement has been one of the recommendations after the event analysis to ensure reliable operation of the bulk power system. In general, the impact of DERs on the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or justification.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to revise requirements to provide clarity or, in some cases, expand the scope of requirements when considering the performance of DERs to ensure the accuracy of Transmission System Planning Assessments.
Project Scope (Define the parameters of the proposed project):
As identified by SPIDERWG, revision to the following sections of TPL-001-5.1 should be considered~~revised~~ to ensure the accuracy of Transmission System Planning Assessments: a. R2.1, R2.2, and R2.4~~2~~, the use of phrase "System peak Load" b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data and models are available. The SDT can consider whether a threshold needs to be established.

[2] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201001_Single_Phase_Fault_Precipitates_Loss_of_Generation_and_Load.pdf

[3] https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. d. R4.3.2, the list of dynamic control devices should include DER so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses. ~~d.~~e. Assuming that revisions to the MOD-032 standard ensure that DER model data is available, modification to the TPL-001 standard should give consideration to potential exclusions of explicit DER modeling based on technical rationale.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[4] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
A detailed description of each Project Scope item is given below: a. R2.1 and R2.2, the use of phrase "System peak Load" With increased penetration of DER, the load that transmission system supplies is the net load (net load = gross load – DER output) as seen at the T-D interface, which might reach its peak during operating conditions that are not at the peak gross load hour. As such, there is a need for individual TPs to be required to document and define their peak load conditions (e.g., gross or net) in their assessments. The SDT should consider adding the terms "Gross Load" and "Net Load" to the NERC Glossary of Terms and updating the term "System peak Load" in the standard to "System peak net Load". In addition, a high gross load hour may be the most stressed load driven condition for contingencies that may trip large amounts of DER. High system peak gross load may be studied as additional scenarios as required by current standard under R2.1.3. b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER if data is available. The SDT can consider whether a threshold needs to be established. The terms "generators" in Sub-requirements 3.3.1.1 and 4.3.1.2 should be clarified. DERs that are explicitly modeled as generators should be tripped where simulations show bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to consider inclusion in the assessment any assumptions made in estimating DER bus voltage.

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

Requested information
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER. For example, the language referring to "pulls out of synchronism" is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). However, large amounts of asynchronous DER tripping on low/high voltage/frequency conditions can also adversely affect BES performance and may pose a risk to system instability for conditions such as cascading, voltage instability, or uncontrolled islanding if not properly studied and identified ahead of real-time operations. It is recommended to expand the stability performance criteria to include both synchronous and asynchronous generation. d. R4.3.2, the standard should recognize that the list of dynamic control devices should consider the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) in stability analyses. The SDT can consider adding asynchronous generator related devices like inverter, plant controller, etc.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Although the cost impact is unknown, costs to Planning Coordinators and Transmission Planners will increase as Transmission System Planning Assessments reflect additional dynamic components and controls. It is anticipated that this cost will vary depending on training, tools, scenario development, and other factors in each Planning Coordinators and Transmission Planners' area.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR will primarily impact Transmission System Planning Assessments, not any specific BES facilities, although as individual IBRs continue to increase in size (e.g. 14MW wind turbines), there may be some impact in the near future.
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 Coordinators and Transmission Planners, i.e. the applicable entities for this standard. Additionally, Distribution Providers, Generator Owners, and DER aggregators participating in markets- i.e. not an applicable entity to this standard, would be useful to include.

Requested information
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.
This SAR is the outcome of the following white paper that was developed by the NERC technical sub-group under the RSTC. • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) Deliverables, and the key findings and recommendations contained within, were thoroughly reviewed and approved by the RSTC.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
No
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.
Among all the issues identified in the NERC SPIDERWG white paper, the ones included in this SAR cannot be addressed by any alternatives. Standard language change will ensure DER impacts being considered appropriately. NERC SPIDERWG will prepare a Reliability Guideline to address the rest of the findings from their white paper.

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.

[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.

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

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

For Use by NERC Only

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

Version History

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

4	February 25, 2020	Standards Information Staff	Updated template footer

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Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	MOD-032-1 Data for Power System Modeling and Analysis		
Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu (NERC SPIDERWG Chair) Bill Quaintance (NERC SPIDERWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	Kun Zhu – MISO Bill Quaintance – Duke Energy Progress		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.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?):			
As the penetration of distributed energy resources (DERs) continues to increase across many distribution systems connected both directly and indirectly to the BES, it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs). MOD-032-1 addresses the gathering of modeling data to perform planning assessments but the standard currently has no specific reference to DER data. This SAR proposes to update MOD-032-1 to: (1) include "data			

Requested information
requirements and reporting procedures"[1] for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise MOD-032-1 to address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments. The goal is to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. The table in Attachment 1 should be updated to include DER in the steady-state and dynamics columns. Details of the changes to be considered by the Standard Drafting Team are included in the "Detailed Description" below. Revision to requirements should also be considered if necessary. b. Based on item a.) and the detailed description below, the SDT should consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary. c. In alignment with the SAR submitted by the previous NERC Essential Reliability Services Working Group (ERSWG), LSE should be removed and replaced by DP as the applicable entity in Section 4.1.3 and all instances in the standard requirements and attachments. d. The SDT should review any potential gaps regarding the de-registration of LSE or based on applicability transfer from LSE to DP (item c in this list), including but not limited to data collection for aggregate DER data. e. Consider modification to the applicability section of the standard that would remove the reference to the Planning Authority and align the applicable entities with the NERC functional model of Planning Coordinator.

[1] See Requirement R1 of MOD-032-1, which requires each TP and PC to develop data requirements and reporting procedures for the collection of modeling data used for the development of models for each PC footprint.

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[2] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (e.g., research paper) to guide development of the Standard or definition):
This SAR proposes to address the issues identified in the project scope above. Specifically, the following details should be considered and addressed by the drafting team: • In the Applicability section of MOD-032-1, LSE should be replaced with DP, in alignment with the SAR previously submitted by ERSWG. Similarly, all relevant uses of LSE should be replaced with DP. ▪ The table in Attachment 1 should include references to aggregate DER in the steady-state and dynamics columns. The drafting team should consider the data needed for modeling aggregate DER for the purposes of reliability studies. In particular, the drafting team should consider the recommendations set forth in *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. • Note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states "all applicable elements" in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently. • In alignment with adding "DER" to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for "Distributed Energy Resource (DER)" to the NERC Glossary of Terms. As stated, SPIDERWG has published *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies* that includes recommended practices and for the collection of aggregate DER data for transmission planning studies. **These materials are not intended to dilute the criticality of this SAR to address the issues identified above within MOD-032-1 itself. Rather, the SDT can use these materials when determining the specific language for inclusion in the standard requirements revisions.**
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts are not fully known.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.* Dispersed Generation Resources):

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

Requested information
DER owners are not subject to NERC Reliability Standards. However, SPIDERWG believes the DP (a NERC Registered Entity) has the information regarding DER connected to its distribution system that is needed for modeling the aggregate behavior of DER for the purposes of BES reliability planning studies. The DP should provide that information to the TP and PC accordingly.
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 Planner, Planning Coordinator, Distribution Provider While not a Functional Entity per the NERC Functional Model, the "MOD-032 Designees" that are designated by the ERO to develop interconnection-wide base cases (i.e., the Regional Entities), will also be affected by these changes and should be considered for appointment to the Standard Drafting Team.
Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The proposals in this SAR were developed by the NERC SPIDERWG, a stakeholder group under the NERC Planning Committee.
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)?
The ERSWG submitted a SAR related to MOD-032-1, as described above. This SAR supports those changes, and further expands on a few necessary additional changes related to DER modeling.
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 NERC SPIDERWG is preparing a Reliability Guideline on data collection for DER modeling. That guideline will provide recommendations for improvements to the data requirements and reporting procedures developed jointly by PCs and their TPs. However, updates to MOD-032-1 are also needed to ensure minimum planning consideration and reporting requirement on DER, particularly in Attachment 1. Therefore, this SAR aligns with the necessary changes to meet the objective.

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.

[3] 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	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

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:	MOD-032-1 Data for Power System Modeling and Analysis		
Date Submitted:	12/15/2021 (Revised on June 22, 2022)		
SAR Requester			
Name:	Kun Zhu (NERC SPIDERWG Chair) Bill Quaintance (NERC SPIDERWG Vice Chair) (Revised by Project 2022-02 SAR Drafting Team)		
Organization:	Kun Zhu – MISO Bill Quaintance – Duke Energy Progress		
Telephone:	Kun – 317-249-5789 Bill – 919-546-4810	Email:	kzhu@misoenergy.org william.quaintance@duke-energy.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?):			
As the penetration of distributed energy resources (DERs) continues to increase across ~~the~~ many distribution systems connected both directly and indirectly to the BES~~North American bulk power system (BPS)~~, it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs). MOD-032-1 addresses the gathering of modeling data to perform planning assessments but the standard currently has no specific reference to DER data. This SAR proposes to			

Requested information
update MOD-032-1 to: (1) include "data requirements and reporting procedures"[1] for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise MOD-032-1 to address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments. The goal is to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. The table in Attachment 1 should be updated to include DER in the steady-state and dynamics columns. Details of the changes to be considered by the Standard Drafting Team are included in the "Detailed Description" below. Revision to requirements should also be considered if necessary. b. Based on item a.) and the detailed description below, the SDT should consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary. c. In alignment with the SAR submitted by the previous NERC Essential Reliability Services Working Group (ERSWG), LSE should be removed and replaced by DP as the applicable entity in Section 4.1.3 and all instances in the standard requirements and attachments. d. The SDT should review any potential gaps regarding ~~data collection for aggregate DER data with~~ the de-registration of LSE or based on applicability transfer from LSE to DP (item c in this list), including but not limited to data collection for aggregate DER data. ~~d.~~e. Consider modification to the applicability section of the standard that would remove the reference to the Planning Authority and align the applicable entities with the NERC functional model of Planning Coordinator.

[1] See Requirement R1 of MOD-032-1, which requires each TP and PC to develop data requirements and reporting procedures for the collection of modeling data used for the development of models for each PC footprint.

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[2] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (e.g., research paper) to guide development of the Standard or definition):
This SAR proposes to address the issues identified in the project scope above. Specifically, the following details should be considered and addressed by the drafting team: • In the Applicability section of MOD-032-1, LSE should be replaced with DP, in alignment with the SAR previously submitted by ERSWG. Similarly, all relevant uses of LSE should be replaced with DP. ▪ The table in Attachment 1 should include references to aggregate DER in the steady-state and dynamics columns. The drafting team should consider the data needed for modeling aggregate DER for the purposes of reliability studies. In particular, the drafting team should consider the recommendations set forth in *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. • Note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states "all applicable elements" in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently. • In alignment with adding "DER" to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for "Distributed Energy Resource (DER)" to the NERC Glossary of Terms. As stated, SPIDERWG has published *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies* that includes recommended practices and for the collection of aggregate DER data for transmission planning studies. **These materials are not intended to dilute the criticality of this SAR to address the issues identified above within MOD-032-1 itself. Rather, the SDT can use these materials when determining the specific language for inclusion in the standard requirements revisions.**
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts are not fully known. ~~However, due to the limited scope of the requested data, cost impact is expected to be minimal to all entities. DPs typically collect the information need to model aggregate levels of DERs in planning assessments. Therefore, data collection effort by the DP would be minimal additional effort. DPs already have processes to provide load data to the TP and PC, so DER data can be~~

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

Requested information
~~managed in a similar manner to reduce cost and effort. If the scope of the required data is expanded, cost impact would likely increase.~~
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
DER owners are not subject to NERC Reliability Standards. However, SPIDERWG believes the DP (a NERC Registered Entity) has the information regarding DER connected to its distribution system that is needed for modeling the aggregate behavior of DER for the purposes of BES reliability planning studies. The DP should provide that information to the TP and PC accordingly.
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 Planner, Planning Coordinator, Distribution Provider While not a Functional Entity per the NERC Functional Model, the "MOD-032 Designees" that are designated by the ERO to develop interconnection-wide base cases (i.e., the Regional Entities), will also be affected by these changes and should be considered for appointment to the Standard Drafting Team.
Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The proposals in this SAR were developed by the NERC SPIDERWG, a stakeholder group under the NERC Planning Committee.
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)?
The ERSWG submitted a SAR related to MOD-032-1, as described above. This SAR supports those changes, and further expands on a few necessary additional changes related to DER modeling.
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 NERC SPIDERWG is preparing a Reliability Guideline on data collection for DER modeling. That guideline will provide recommendations for improvements to the data requirements and reporting procedures developed jointly by PCs and their TPs. However, updates to MOD-032-1 are also needed to ensure minimum planning consideration and reporting requirement on DER, particularly in Attachment 1. Therefore, this SAR aligns with the necessary changes to meet the objective.

[3] 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.

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Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
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☐	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.
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Region(s)/ Interconnection	Explanation
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2	June 28, 2017	Standards Information Staff	Updated template

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-1**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority

is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified

						in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

			steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;

			by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service

			Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO]	6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	purposes. [BA, GO, LSE, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

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

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:

   a. add requirement identifying who provides and who receives data;
   b. identify acceptability;
   c. standard format;
   d. how to deal with new technologies (user written models if no standard model exists); and
   e. shareability.

4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving	See Implementation Plan

		MOD-032-1.	posted on the Reliability Standards web page for details on enforcement dates for Requirements.

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022

Anticipated Actions	Date
45-day formal or informal comment period with ballot	6/1/2023 – 7/17/2023
45-day formal or informal comment period with additional ballot	9/1/2023 – 10/15/2023
XX-day final ballot	
Board adoption	12/12/2023

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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing active power in non-isolated parallel operation with the Bulk Electric System.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar

days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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 applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 the 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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required

						components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data

			Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within	Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability,

			the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission

			Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

				or Transmission Planner).	or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-2 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [DP, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Demand [DP, TO (when a Demand is not associated with a registered DP)] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Distribution Provider (DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	8. Static Var Systems and FACTS [GO, TO, DP] 9. DC system models [TO] 10. Distributed Energy Resource (DER) data [DP, TO (when DER is not associated with a registered DP)] 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
9. Distributed Energy Resource (DER) data[4] [DP, TO (when DER is not associated with a registered DP)] a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS b. Real power capability (minimum and maximum) c. Reactive power capability (minimum and maximum) d. Generator type (solar, battery, etc.) e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control. 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

[4]The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance.

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022

Anticipated Actions	Date
45-day formal or informal comment period with ballot	6/1/2023 – 7/17/2023
45-day formal or informal comment period with additional ballot	9/1/2023 – 10/15/2023
XX-day final ballot	
Board adoption	12/12/2023

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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing active power in non-isolated parallel operation with the Bulk Electric System.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 ~~Load Serving Entity~~Distribution Provider

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This ~~proposed~~ standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the ~~proposed~~ standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

   ~~MOD-032-21, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-21, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a~~

~~standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~**6. Background:**~~

~~MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.~~

~~The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).~~

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying

Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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.

~~"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. "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 ~~Assessment~~ Enforcement Program~~Processes~~: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

~~**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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required

						components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided

			Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short	Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to	Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of

			circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

			Coordinator or Transmission Planner).	calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

~~None.~~

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

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

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

reduce the quantity of MOD standards;

add short circuit data as a requirement to the MOD standards; and

supply data and models:

add requirement identifying who provides and who receives data;

identify acceptability;

standard format;

how to deal with new technologies (user written models if no standard model exists); and

a. shareability.
b. These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
c. The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
d. Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.
e. Rationale for R2:
f. This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."
g. **Rationale for R3:**
h. In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.
i. This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about

the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts."* (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection-wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0,

			MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-~~01~~ 2 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [~~LSE~~DP, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Demand [~~LSE~~DP, TO (when a Demand is not associated with a registered DP)] 6. Wind Turbine Data [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), ~~Load Serving Entity~~Distribution Provider (~~LSE~~DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A ~~Load Serving Entity~~Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point*	7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC system models [TO] 10. Distributed Energy Resource (DER) data [DP, TO (when DER is not associated with a registered DP)] ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data~~-~~ [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
c. fixed/switched shunt, if applicable d. in-service status* 9. Distributed Energy Resource (DER) data[4] [DP, TO (when DER is not associated with a registered DP)] a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS b. Real power capability (minimum and maximum) c. Reactive power capability (minimum and maximum) d. Generator type (solar, battery, etc.) e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control. ~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]		

[4]The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance.

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Implementation Plan

Project 2022-02 Modifications to TPL-001 and MOD-032
Reliability Standard MOD-032-2

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis

Applicable Entities

- Balancing Authority
- Generator Owner
- Distribution Provider
- Planning Coordinator
- Resource Planner
- Transmission Owner
- Transmission Planner
- Transmission Service Provider

NERC Glossary of Terms

This section includes a newly defined term used in the NERC Reliability Standard. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed New Definition(s):
Distributed Energy Resource (DER):

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing active power in non-isolated parallel operation with the Bulk Power System.

Background

As the penetration of distributed energy resources (DERs) continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Proposed Reliability Standard MOD-032-2 replaces the Load-Serving Entity as an applicable entity with the Distribution Provider and updates Attachment 1: Data Reporting Requirements with data specific to DERs.

General Considerations

In developing this implementation plan, the standard drafting team considered the time that would be necessary to develop data requirements and reporting procedures for data related to DERs, including identifying the proper reporting entity. The standard drafting team also considered that the standard would become applicable to the Distribution Provider for the first time.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource 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 MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Definition – Distributed Energy Resource (DER)

Where approval by an applicable governmental authority is required, the definition of Distributed Energy Resource (DER) shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1

Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance Dates

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032-2.

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Unofficial Comment Form

Project 2022-02 Modifications to TPL-001 and MOD-032

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-02 Modifications to TPL-001 and MOD-032** by **8 p.m. Eastern, Friday, July 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

Project 2022-02 addresses multiple Standard Authorization Requests (SARs) related to transmission planning and modeling data and analysis (MOD-032-1 Data for Power System Modeling and Analysis SAR from the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG); TPL-001-5.1 Transmission System Planning Performance Requirements SAR from NERC Inverter-Based Resource Performance Working Group (IRPWG); and TPL-001-5.1 Transmission System Planning Performance Requirements SAR from the SPIDERWG).

The Project 2022-02 Standard Drafting Team decided to break this project into two phases since there are two Reliability Standards involved and the project scopes are quite different. Phase one addresses MOD-032-1 in data collection and phase two will address TPL-001-5.1 in the accuracy of transmission system planning assessments. This posting affects phase one of this project only (MOD-032). TPL-001 will be addressed during phase two of this project.

Questions

1. Do you agree with the modification to remove “Load Serving Entity” and replace with “Distribution Provider” in MOD-032-2?

   ☐ Yes
   ☐ No

   Comments:

2. 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 2022-02 Modifications to MOD-032-2

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 MOD-032-2. 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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R1

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R2

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R3

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

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Technical Rationale for Reliability Standard MOD-032-2

May 2023

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. Items in Attachment 1 that were previously required to be provided by the LSE are now required to be provided by the DP. It is recognized that some distribution facilities do not have an associated DP that meets the NERC registration criteria. In such instances, the specified data is required to be provided by the Transmission Owner (TO) or registered DP to which those facilities are connected. It is expected that TOs (or registered DPs) may need to coordinate with the owners of distribution facilities that do not have an associated NERC-registered DP to ensure the availability of the necessary data, either through interconnection agreements or other binding contracts.

Additionally, the standard drafting team (SDT) reviewed the dual applicability to Planning Authority and Planning Coordinator and determined that that the explanation from MOD-032-1 is still correct and valid with minor edits as proposed. The posted "Appendix 5B: Statement of Compliance Registry Criteria", dated January 19, 2021, still uses the Planning Authority term.

Rationale for Distributed Energy Resource (DER) Definition

The SDT considered various DER definitions utilized in the industry and discussed in the SPIDERWG Terms and Definitions Working Document. The SDT chose to refer to technologies connected to the DP's system to avoid ambiguities associated with defining a distribution system. The NERC glossary definition for DP notes that the DP is defined by providing the distribution function (this includes entities that may not be NERC-registered DPs). Additionally, by specifying facilities that produce active power, the scope is focused on only those facilities that may be exporting real power to the power system or offsetting real power load (e.g., residential solar or commercial rooftop solar, even if they only operate at unity power factor or don't have any reactive power capability). This would exclude examples such as charging-only electric vehicle (EV) installations and controllable load options. The SDT included "in non-isolated parallel operation with the Bulk Power System." to indicate that distributed energy resources with potential BES reliability impacts are those that are actually electrically connected to the BES. Resources that are only operated in an islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BES and therefore are not of interest from a BES-reliability perspective. The SDT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry.

The SDT consensus is that this definition clarifies what is in scope and out of scope with respect to where DER is connected rather than the technology type. Utilizing the existing NERC definition for DP and the associated area of responsibility aligns with the scope of DER data collection and modeling activities and

provides clarity for the industry to aid in gathering this information. It should be clear that MOD-032-2 applicability and compliance obligations refer to NERC-registered DPs; the use of the DP term in the DER definition does not in itself imply any compliance obligation.

Rationale for Modifications to Attachment 1

MOD-032-2 Attachment 1: Data Reporting Requirements was updated with data specific to DERs. The intent is that all relevant DER data including both utility scale facilities (commonly referred to as U-DER) and smaller behind-the meter facilities (commonly referred to as R-DER) be available and represented in models of the interconnected transmission system consistent with the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum amount of information expected to be needed to reasonably represent DER in transmission system models. It is expected that aggregate DER (rather than individual DER facilities) would be represented in most Planning Coordinator/Transmission Planner (PC/TP) study models. However, footnote 4 explicitly allows the PC/TP to require either aggregated or unaggregated DER data. This provides flexibility for local practices wherein the PC/TP may elect to apply DER aggregation assumptions rather than depend on the DP/TO to apply aggregation assumptions.

The PC/TP may have access to sufficient data for modeling certain DER through alternative means (e.g., direct registration of DER in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DER that are excluded from the DP/TO obligation for providing DER modeling data. This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.

The SDT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with the required data are only presented in the “steady state” column (though arguably such data is also relevant to “dynamics” and/or “short circuit”). The addition to the “dynamics” column was limited to the “Distributed Energy Resource (DER) data” line item. The SDT concluded that this was appropriate and consistent with other “dynamics” line items such as “Wind Turbine Data” and “Photovoltaic systems” that are listed without detailed sub-bullets. Drastically altering the structure of Attachment 1 or adding DER data to the “short circuit” column was beyond the scope of the Project 2022-02 SAR.

It should be noted that the modifications do not make DER facilities subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases. There are already existing requirements for DPs (or TOs) to provide information about load connected to their systems. Similar to load, DER is not generally considered to be a BES facility. However, BES reliability assessments require an accurate representation of both aggregate load and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient DER data is available to the PC/TP so that appropriate DER representations can be included in their BES reliability assessments.

- **Inclusion of In-Service Date or Other Information**

As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DER may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DER installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate ride-through characteristic representation for DER in that area could be inferred by the in-service date of the DER. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed to make inferences regarding the overall aggregate DER response characteristics.

- **Inclusion of Data Related to DER Feeders Subject to UFLS and/or UVLS**

There is a reliability need for the DP/TO to convey this information to the PC/TP. As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DER subject to each UVLS/UFLS tripping stage should be identified.

- **Inclusion of Aggregate Demand Clarification**

Footnote 2 was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DER is not consistent with a modeling framework that explicitly represents DER.

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Standards Announcement

Project 2022-02 Modifications to TPL-001 and MOD-032

Formal Comment Period Open through July 14, 2023
Ballot Pools Forming through June 29, 2023

Now Available

A 45-day formal comment period for **Project 2022-02 Modifications to TPL-001 and MOD-032** is open through **8 p.m. Eastern, Friday, July 14, 2023** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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, Thursday, June 29, 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 **July 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 2022-02 Modifications to TPL-001 and MOD-032 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:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 - MOD-032-2
Comment Period Start Date:	5/31/2023
Comment Period End Date:	7/14/2023
Associated Ballots:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan IN 1 OT 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 IN 1 ST 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 IN 1 NB

There were 77 sets of responses, including comments from approximately 200 different people from approximately 126 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modification to remove “Load Serving Entity” and replace with “Distribution Provider” in MOD-032-2?

2. 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
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Public Utility District No. 1 of Chelan County	Anne Kronshage	6		Public Utility District No. 1 of Chelan County - Voting Group	Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	1	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1	Ali Miremadi	CAISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Helen Lainis	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Elizabeth Davis	PJM	2	RF

					Charles Yeung	SPP	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
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
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	RF
					Scott Berry	Wabash Valley Power Association	3	RF

					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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
National Grid USA	Michael Jones	1		National Grid	Michael Jones	National Grid USA	1	NPCC
					Brian Shanahan	National Grid USA	3	NPCC
Southern Company - Southern	Pamela Frazier	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					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
Patricia Robertson	Patricia Robertson		WECC	BC Hydro Balloters	Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Hootan Jarollahi	BC Hydro and Power Authority	3	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	6	NPCC

						Department of Public Service		
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Joshua London	Eversource Energy	1	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					David Duhart	Southwest Power Pool Inc.	2	MRO
					Debbie Currie	Southwest Power Pool Inc	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Hugh Benfer	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Lottie Jones	Southwest Power Pool Inc.	2	MRO
					scott Jordan	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc.	2	MRO

					Theo Brown	Southwest Power Pool Inc.	2	MRO
					Amber Wallace	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC

					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree with the modification to remove "Load Serving Entity" and replace with "Distribution Provider" in MOD-032-2?

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer

Answer	No
Document Name	

Comment

To be clear, the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change is incomplete, misappropriates modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data, as well as retains a significant reliability gap.

Transmission Owners who are not Distribution Providers likely have no knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. Transmission Owner visibility for load demand is typically limited to historical telemetered MW and MVAR data. This finding, especially with regards to DERs, has already been well-documented. A key recommendation in the NERC Reliability and Security Technical Committee (RSTC) subcommittee approved the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was:

"TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements or practices that will ensure this data is available. ***As the TPs, PCs, and TOs are dependent on the DP to have the data made available****, this will likely require actions from state regulatory bodies and DPs to establish requirements to gather this information" (page 7 of 61).*

The SDT should consider that Transmission Owners should not be held accountable for demand and DER data that they have no cognizance of. Additionally, the SDT should remember that most DER are smaller than the BES resource threshold or reside on a distribution system. The threshold for an entity to be registered as a Distribution Provider is 75 MW of load. This implies that the majority of DERs are and will be connected to systems outside the scope and visibility of Transmission Owners, as well as existing Distribution Providers. To emphasize this reality: as of 15 May 2023, there were 314 Distribution Providers registered with NERC (excluding UFLS-only DPs). Of those DPs, 96 were not otherwise registered as either a PC, TP, or TO. While it may be misunderstood that only 96 DPs may become newly applicable and participatory in model data collection given the draft changes to MOD-032-2, this ignores that the latest EIA 861 data (collected in 2021; published in 2022) reflects about 1,190 distribution utilities reflecting almost 197,000 distribution circuits in the continental US. In other words, it may be reasonable to conclude that 74% of the distribution utilities in the US do not meet the NERC registration threshold. Furthermore, PCs, TPs, and TOs have no regulatory relationship with these unregistered entities and cannot be held responsible for DER data for which that are not aware.

In June 2022, NERC published its "Inverter-Based Resource Strategy" that recognized efforts necessary to analyze the breakdown of resource size, location, type, and applicability with the BES definition to make a determination of whether the current BES threshold should be updated to reflect the changing resource mix" (page 9 of 10). Subsequently, the NERC Member Representatives Committee (MRC) and Board of Trustees (BOT) technical session on inverter-based resources in February 2023 emphasized the need for a focus on functional registration noting: "industry is increasingly challenged with addressing reliability issues for unregistered inverter-based resources, and those resources are reaching critical mass in some parts of the country. The lack of requirements currently imposed on those resources creates local and regional reliability risks to the BPS in aggregate. This issue compounds in many areas with the growing presence of distributed energy resources (DERs) connected to the distribution system." In response to the FERC directive "Registration of Inverter-based Resources", NERC filed a proposal to modify its Rules of Procedure to "include a new function comprised of owners of IBRs interconnected to the BPS." The Generator Owner – Inverter-Based Resource (GO-IBR) registration would include "owners of IBRs which have aggregate nameplate capacity of less than or equal to 75 MVA and greater than or equal to 20 MVA interconnected at a voltage greater than or equal to 100 kV; or Owners of IBRs which have aggregate nameplate capacity of greater than or equal to 20 MVA interconnected at a voltage less than 100 kV."

Given the anticipated GO-IBR functional registration, the NERC Project 2022-02 SDT should modify MOD-032-2 Attachment 1 to specify **DP, GO-IBR** are responsible for Aggregate Demand, Demand, and Distributed Energy Resource (DER) data, as well as other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	No
Document Name	

Comment

Comments to be supplied separately by AECC's Ayslynn McAvoy.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	

Comment

WECC supports the removal of Load Serving Entity as that registration no longer exists. However, WECC believes that adding Distribution Provider is not necessary as explained below.

Including the registered Distribtuion Provider in the applicability of the standard complicates compliance applicability and monitoring. It requires two processes and two monitoring mithods instead of one.

The technical rational for the standard states that for distribution facilities which have no Distribution Provider, or which do not connect to a Distribution Provider, the Transmission Owner is responsible for coordinating to obtain the necessary data. If the TO can perform this for distrbution facilities that do not have a registered DP, they can use the same process to obtain the data from a registered DP.

This removes the need of potentially complex determination of standard applicability and the research needed to determine applicability for each Transmission Owner based on the existence of registered Distribution Providers or any other non-BES load that has no registered DP. It also makes clear that the Planning Coordinator and Transmission Planner would be receiving bus level demand data from a single source (The Transmission Owner) rather than obtaining data from multiple DP’s and TO’s.

If there is a concern that without a standard requirement to support it, a registered DP would not provide the required data to a TO or TP then how could it be expected that a non-registered entity would provide this information. The TO has the authority to obtain this data for any entities connected to its system via FAC-002.

If it is decided to continue to include Distribution Providers in the applicability, please clarify the applicability and obligation of the “registered” (USLF)-Only DP. Would MOD-032 now be applicable to all USLF only Distribution Providers?

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

The definition of Distribution Providers is limited by the current definition of Distribution providers to the entity that operates the wires between the Transmission system and the end-user. This is a short-cut to getting the DERs included in the standard. I recommend editing the definition of Distribution Provider to include those entities that are responsible for the operation and balancing of DERs if this is how the SDT wants to address this issue.

Likes 0	
Dislikes 0	

Response

Thomas Standifur - Austin Energy - 1

Answer	No
Document Name	

Comment

Austin Energy supports APPA's comments.

Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs’ and TOs’ responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data’s completeness or accuracy”

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

LCRA notes that the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change inappropriately assigns modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data. Transmission Owners who are not Distribution Providers likely have limited knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. This finding, especially with regards to DERs, was identified in the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)

Likes 0	
Dislikes 0	

Response

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer

Answer	No
Document Name	

Comment

Oncor does not agree with the Load Serving Entity ("LSE") to Distribution Provider ("DP") terminology modification. Even for Transmission Owners that are also DP (like Oncor), there are many instances in which we interconnect and deliver transmission-level service to another DP. In these cases, Oncor would not have access to the DER modeling parameters listed in Attachment 1 or visibility into the other DP's system other than the aggregated load provided.

We further disagree with the changes outlined in Attachment 1 in the Steady-State column of Table – #9, which are being proposed in conjunction with the change in terminology from LSE to DP. It will be more appropriate to specify general model requirements in MOD-032 and allow Planning Coordinators and Transmission Planners to determine model details that are appropriate for their established processes and methodologies. Also, it may be impossible to provide individual specifications for Retail Scale DER such as reactive capability and in-service date.

Also, Oncor would like further clarification on the following:

1. "a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS"
    - Could the SDT elaborate on how knowing that a DER is on a UFLS feeder could impact the results of a Steady State analysis? We do not see the need for the UFLS data in the Steady State column.
2. "b. Real power capability (minimum and maximum)"
    - Is this referring to the nameplate or approved capacity?

- Is the meaning of *minimum* equivalent to approved capacity? And is *maximum* equivalent to nameplate capacity?

3. “c. Reactive capability (minimum and maximum)”
   - Oncor does not typically track reactive power data for currently installed DER.
4. “d. Generator type (solar, battery, etc.)”
   - Oncor recommends modifying this statement to give instruction on how to report a single location with multiple types of DER.
5. “e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.”
   - Can you define the in-service date? In Oncor’s experience, some DER projects will connect to our system, test, and then permission is granted to operate. For some of the DER projects, we give permission for them to operate; but the project is not energized until the DER facility is ready on their end. Typically, the registered resources that participate in ancillary services go in-service before they are permitted to operate for testing purposes.
   - This is not practical for DERs that are modeled in an aggregated manner.

Likes 0	
Dislikes 0	

Response

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins

Answer	No
Document Name	

Comment

LCRA TSC notes that the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change inappropriately assigns modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data. Transmission Owners who are not Distribution Providers likely have limited knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. This finding, especially with regards to DERs, was identified in the “Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline” developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG).

Likes 0	
Dislikes 0	

Response

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	

Comment
A specific definition of DER should be included in the standard. A specific MW threshold for the inclusion of a DER in the interconnected transmission system model data should be included in the standard

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	

Comment
FE supports the removal of “Load Serving Entity” and supports the addition of “Distribution Provides” in MOD-032-2.

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment
Load Serving Entity is no longer an active NERC registration code. BPA agrees that replacement is appropriate. However, Attachment A adds a parenthetical that states the Transmission Owner (TO) is responsible when a Demand or DER is not associated with a registered DP. That would put the responsibility on BPA as the TO. What if the TO cannot get non-BES DER data from an unregistered customer? As long as BPA is held responsible for providing data as the TO (that we do not have the authority to require from an unregistered DP), our vote will be NO.

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behald of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,7 - SERC	
Answer	Yes
Document Name	2022-02_Unofficial Comment Form_May2023.docx
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	

PG&E agrees with the modification to remove the “Load Serving Entity” (LSE) and replace it with ‘Distribution Provider” (DP) since the LSE designation has been retired.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments	

Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the removal of Load Serving Entities (LSE) and the addition of Distribution Providers (DP) as an appropriate LSE replacement.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the removal of Load Serving Entities (LSE) and the addition of Distribution Providers (DP) as an appropriate LSE replacement.	
Likes 0	

Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports the comments of the EEI	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Yes, this change will be helpful in obtaining DER data for transmission planning studies	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Agree with EEI comment: {C}· To better clarify the extent of DER resources that must be reported under MOD-032, EEI suggests that a Facilities section be added to this Reliability Standard.	

{C}· Footnote 2 – EEI asks that the SDT provide additional clarity regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While we understand why this would be desirable, most small DERs are not metered except for billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. We are further concerned that the manhours required to account for these DER offsets could be substantial adding excessive costs while providing questionable value to this change. As an alternative, EEI suggests that DPs and TOs could provide estimated DER offset values, which would require fewer manhours to develop and should provide sufficient value to the planning models.

{C}· Steady-state and Dynamic columns

EEI is concerned that the data requests identified in Item 9 (Steady-state), and Item 10 (Dynamic) seek non-aggregated data, while the SAR specifies that aggregated DER data is to be supplied. To address this concern, we ask that both Items 9 and 10 be edited to make it clear that data requests to DPs and TOs are to be limited to aggregate DER data.

{C}· Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states “TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary”. This appears to go beyond the approved limits of this SAR and should therefore be removed.

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 comment of EEI which states:

"EEI supports both the removal of Load Serving Entities (LSE) and the addition of Distribution Providers as an appropriate LSE replacement."

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern Company supports comments submitted by 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	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for queston #1.	
Likes 0	
Dislikes 0	
Response	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) is supporting the proposed MOD-032-2 modification to replace Load Serving Entities (LSE) with Distribution Providers (DP).	
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 Co. (SIGE) is supporting the proposed MOD-032-2 modification to replace Load Serving Entities (LSE) with Distribution Providers (DP).	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
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 both the removal of Load Serving Entities (LSE) and the addition of Distribution Providers as an appropriate LSE replacement.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1	
Answer	Yes
Document Name	
Comment	

The The **ISO/RTO Council Standards Review Committee ("SRC")** [1] supports the replacement of "Load Serving Entity (LSE)" with "Distribution Provider (DP)." This is a vast improvement over where MOD-032 stands today as this will fill the gap left by the retirement of the LSE function.

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO, IESO, ISO-NE, MISO, NYISO, PJM, SPP and ERCOT (with the exception of the response to question 2).

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

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; - James Mearns

Answer	Yes
Document Name	

Comment

This modification appears to meet the intent of the SAR by addressing the paralleled DERs that are presently not modelled within Distribution Provider's system models. While some argument could be made concerning the minimal impact on system planning studies caused by Distribution Customer's DER deployment, it is important to set a standard approach toward assessing potential impacts, and these requirements are not substantially burdensome.

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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
For this response, ERCOT joins the comments submitted by the ISO/RTO Council Standards Review Committee and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Allete - Minnesota Power, Inc. - 1 - 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	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
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; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
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	

Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 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	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 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	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
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	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	

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	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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	
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	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Desmarie Waterhouse - American Public Power Association - 4 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
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	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE supports the modification to remove Load Serving Entity (LSE) and replace with Distribution Provider (DP) as LSE is no longer a registered function. Texas RE has some concerns, however, regarding the actions required by the DP in gathering Distributed Energy Resource (DER) data. There seems to be a potential gap for getting the DER data for Power System Modeling and Analysis as written. DPs are not typically the owners of the DER data and there are no current NERC registration or requirements for the owners of the DER data to provide the data to DPs. As written, the compliance responsibility for providing the DER data falls on the DP who may not authority or a robust process to get the data from the current and future DER owners. Texas RE recommends a requirement that the registered entity managing DERs provide the data to the DPs. Additionally, that non-registered DERs should be captured effectively to ensure reliability operations.

Texas RE does agree that the DPs should be responsible for providing the equivalent system impedance data (distribution feeder, power transformer, etc.) for the DER connections.

The Standard does not specify a threshold limit for the DER facilities required to provide the data. Texas RE recommends the ‘Term(s)’ section include a distinction between utility scale DERs (commercial level DERs, utility scale solar facilities, etc.) and aggregated level DERs (residential rooftop solar, small generators, residential batteries, etc.).

Texas RE understands the intention of the modifications to MOD-032 is to provide visibility of DER in planning models and achieve consistency in representation of various types of DER. To avoid double-counting DERs in the models, Texas RE recommends identifying whether or not the DER outputs are embedded in the load forecasts used in the models and that this is aligned with the demand and energy data that is needed for MOD-031-3.	
Likes 0	
Dislikes 0	
Response	

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

Mike Gabriel - Greybeard Compliance Services, LLC - 5

Answer	
Document Name	

Comment

In lieu of creating yet another definition, we recommend using one of the existing definitions in Table D.1 of the SPIDERWG document: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf, or potentially using the NERC Distributed Energy Task Force (ERTF) DER definition: Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom

Answer	
Document Name	

Comment

Buckeye agrees with the comments prepared by ACES:

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may or may not have a material impact to the reliability of the BES. Additionally, we have concerns regarding footnote 4 on the last page of the Attachment 1. This footnote states: "The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance."
This statement seems to allow some discretion for allowing "local practices" to then dictate what classifications of DER are to be modeled in aggregate versus otherwise. If that is the case, then it seems to conflict with the stated goal of the MOD-032-1 SAR to "…provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data." We recommend that a non-zero MVA threshold be established below which DER data will be modeled in aggregate and above which DER data will be modeled explicitly. Allowing such "local practices" to dictate which DERs are to be modeled in aggregate or not seems contrary to having a standard for the industry to implement that is intended to provide clarity and consistency.
Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	2022-02_Unofficial Comment Form_ERCOT Comments.docx
Comment	

ERCOT generally supports DER-related data collection and recommends that it occur at an early stage (steady-state) of model development. ERCOT requests the following revisions and clarifications to the draft standard.

1. Dual Planning Authority (PA) / Planning Coordinator (PC) Designation

While there is justification to reference both the Planning Authority and Planning Coordinator in the Applicability section (section 4), since Appendix 5B: Statement of Compliance Registry Criteria of the NERC Rules of Procedure, dated January 19, 2021, still uses both terms, the explanatory paragraph in Part 4.1.4 refers to synchronization between registration criteria and the NERC functional model, which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, ERCOT requests the explanatory paragraph be deleted from Part 4.1.4, which would then read as follows:

4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

2. Planning Coordinator (PC) Interface

ERCOT notes the importance of retaining the PC's flexibility with respect to determining the process used to acquire modeling data. While some PCs prefer to interface directly with the DP as noted in footnote 2 (*see* page 20 of 22 of the standard), other PCs prefer to interface with the Transmission Owner (TO) or Transmission Planner (TP). In the latter example, the TO or TP maintains the interface with the DP.

In support of this flexibility, ERCOT requests the SDT revise the table in Attachment 1 by removing the last sentence from footnote 2, adding a new footnote 3 to the first reference to DP in the steady-state column, and renumbering the remaining footnotes as needed, as proposed below:

2. Aggregate Demand*2* [DP*3*, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status*

Footnote 2: For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.

Footnote 3: Wherever DP is noted as the functional entity responsible for reporting data in Attachment 1, a Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

3. Attachment 1, *steady state* column, item 9

a. Strike "feeder" to provide the TP/PC with flexibility in tracking the status of UVLS and UFLS (i.e. as aggregated values or as individual feeders).

b. Clarify the use of "and/or" with regards to UVLS and UFLS. Using "and/or" creates four possible combinations that must be tracked: UFLS only, UVLS only, both UFLS and UVLS, and neither UFLS nor UVLS. Is the intent of the SDT to track all these possible permutations?

ERCOT requests that the SDT modify item 9 to read as follows:

9.a. Location (bus from item 1) and if DER is subject to UFLS and/or UVLS

b. Real power capability (gross minimum and maximum)

c. Reactive power capability (gross minimum and maximum)

4. Attachment 1, existing footnote 4 - clarify the use of "/" by revising the footnote to read as follows:

4 The modeling data requirements and reporting procedures that the PC and TP jointly develop under R1 may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance.

5. Clarify the intent of the short circuit column

The technical rationale states that "[d]rastically altering the structure of Attachment 1 or adding DER data to the 'short circuit' column was beyond the scope of the Project 2022- 02 SAR," which in turn states "note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states 'all applicable elements' in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently."

While the dynamics column was edited to include Distributed Energy Resource Data to match the format of the Dynamics column, the short circuit column was not updated per the reasoning given in the technical rationale and SAR. However, the short circuit column includes the bullet "[p]rovide for all applicable elements in column 'steady state' [GO, RP, TO]," which could be interpreted to compel the relevant entities to collect DER information in the short circuit models if it is deemed an applicable element. ERCOT requests that the SDT confirm that the TP/PC would determine if DER information is an applicable element for short circuit models.

6. Clarify the note regarding data that vary with system operating state and conditions

The steady-state column of Attachment 1 indicates that "[i]tems marked with an asterisk indicate data that vary with system operating state or conditions." ERCOT recommends that the SDT clarify or provide additional information regarding what types of system operating states or conditions are contemplated. For example, if a data element changes seasonally, should the element be marked with an asterisk, or are seasonal variations not considered "system operating state[s] or conditions" for purposes of Attachment 1?

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

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may or may not have a material impact to the reliability of the BES.

Additionally, we have concerns regarding footnote 4 on the last page of the Attachment 1. This footnote states: “The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance.”

This statement seems to allow some discretion for allowing “local practices” to then dictate what classifications of DER are to be modeled in aggregate versus otherwise. If that is the case, then it seems to conflict with the stated goal of the MOD-032-1 SAR to “…provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.” We recommend that a non-zero MVA threshold be established below which DER data will be modeled in aggregate and above which DER data will be modeled explicitly. Allowing such “local practices” to dictate which DERs are to be modeled in aggregate or not seems contrary to having a standard for the industry to implement that is intended to provide clarity and consistency.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

The SPP RTO recommends the drafting team revise the original Standard Authorization Request (SAR) to keep the project open and coordinate with other NERC drafting teams to address data collection efforts that are applicable to the Inverter-Based Resource (IBR) and Energy Storage Resource (ESR-Batteries). This coordination effort will create a level of proficiency and efficiency in the areas of creating accurate models that can be used by the appropriate entities in their study processes to generate quality results that address initial concerns applicable the reliability of the grid.

The drafting team should conduct a cost analysis to help industry understand the cost impacts of this project.

Additionally, the drafting team should consider a resource analysis to help industry understand the additional time required for their resources to participate in these efforts if the project is extended for a certain amount of time.

As for concerns, one of them focuses around NERC suggesting new responsibilities being applicable to the PC and TP in reference to modeling as well as studying process in reference to the reliability of the grid. For example, NERC suggests that there is a need to conduct an EMT study ever so often to help identify issues in a PC and TP footprint; however, the EMT standard has not been approved by the NERC Board of Trustees (BoT) nor FERC at this point. The RSTC has identified that the MOD-032 standard current doesn’t align with such data collection efforts to assist industry, specifically the PC and TP, in this type of process. These data collection gaps need to be resolved prior to giving the PC and TP related responsibilities.

Furthermore, there will be a need to align with the proposed MOD-026-2 standard in reference to the IBRs from a PC and TP perspective (PC and TP creating a process for GOs and TOs to access models).

Moreover, NERC has identified that PRC-024-3 doesn’t provide the information needed to address IBR ride-through with the occurrence of a system disturbance. From our perspective, there will be a need for data collection via MOD-032 to help ensure an appropriate performance standard can be developed to address NERC’s reliability concerns and needs.

Finally, our last concern pertains to the definition of the DER. There are several definitions currently used in industry, including the SPIDERWG's definition. We recommend that the drafting team coordinate with NERC legal to structure one definition (vetted via standard development process) for industry use. Without a common Glossary Term, there is a potential that the various definitions of DER will create confusing as well as reliability/compliance risks for the PC and TP..

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	
Document Name	

Comment

Taunton Municipal Lighting Plant (TMLP) understands and respects the defined need for additional DER modeling data as these resources continue to grow behind-the-meter and beyond the visibility of PCs and BAs. Our concerns with the modifications to MOD-032 are simply to ensure that they require what we can reasonably expect to provide given current configurations. Adding all of the changes that the SDT proposed concerns us that we will continue to add costs to these projects and continue to prevent their viability. Below are additional comments on a few specific proposed revisions to MOD-032:

Proposed DER Definition: The project team is proposing to define a new term of DER to the NERC Glossary. We request additional clarity and background on the development on this definition. We have reviewed the Technical Rationale document that explains its development on Page 1, but it still remains unclear to us what could be considered to have "parallel operation" with the BES versus being a non-BES asset. TMLP requests that we consider a definition that better aligns with the BES definition and its inclusions/exclusions as this will be better understood by DPs.

Att. 1, Steady State Column, New Item 9: The request to provide real and reactive capability, as well as generator type, is within reason as it is readily available information.

Att. 1, Dynamics Column, New Item 10: TMLP requests additional clarity on the parenthetical that requires a distinction of an "*association*" between the DER and the DP, without which the TO is expected to be responsible. In either scenario, it will be unreasonable to expect the DP or TO to provide dynamic modeling information of the DERs. Currently, the DP is typically the host through a Power Purchase Agreement but are not requiring that DER developers provide dynamic modeling information, and the added cost to do so must be considered. At a minimum, the SDT should limit any TO/DP obligations to what is feasible and reasonable, and presently dynamic information for unregistered DERs is not available to us (as a DP) and other DP peers. Expecting a DP or TO to provide this information would require them to alter their interconnection agreements for future projects, as well as sending them on a "research mission" for their existing resources. Further on this point, TMLP agrees with APPA's comments which state "*While DPs may receive some or all of this information at the interconnection request stage, and can pass whatever data they have to their PC and TP, the draft standard must be revised to account for the fact that the DPs and TOs do not own or control these DERs, and thus cannot be held responsible for the completeness or accuracy of the data they themselves receive from the DER owners."*

tt. 1, Steady-State Column, Footnote 2 on "Aggregate Demand": This effectively provides the authority for the host PC/TP to request that DPs reconstitute their load readings prior to submitting, however, the DP's typically are not using revenue quality metering with their DERs and therefore cannot be relied upon for market reporting. If this is not the intended use of the data, then this needs to be clarified in this footnote. The Technical Rationale document states that current collection and modeling of net demand is not consistent with "a modeling framework that explicitly represents DER," and if this is true, then we need to understand what this framework is. We reside in ISO-NE and their market rules currently define the inputs to *Regional Network Load* to exclude "load served by behind-the-meter generation" (ISO-NE OATT, Section II.21.2).

Likes 0	
Dislikes 0	

Response
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis
Answer	
Document Name	
Comment
In addition to PJM supporting the IRC SRC comments, PJM wants to ensure the coordination of Distribution Provider (DP) data is coordinated between the DP and Transmission Owner (TO). The coordination between the DP and TO is needed to properly model due to the DP interconnection with the TO. Thus, each Transmission Owner shall work with the Distribution Provider(s) within the Transmission Owner's area in collecting data for the PA and PC in order to properly model this information and how it interconnects with the Transmission Owner systems. PJM is requesting this information to be written directly in the Standard to ensure accurate and proper data collection. PJM wants to the thank the Standard Drafting Team for all their work and commitment to the Project!
Likes 0	
Dislikes 0	
Response
David Jendras Sr - Ameren - Ameren Services - 3
Answer	
Document Name	
Comment
None
Likes 0	
Dislikes 0	
Response
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6
Answer	
Document Name	
Comment
For the dynamics column in Attachment 1, it is unclear as to what DER data may be requested from the DP. Seminole recommends the drafting team to provide additional clarification, similar to what the dafting team provided in the steady state column, for the data to be collected in the dynamics column.

Likes 0	
Dislikes 0	
Response	
Desmarie Waterhouse - American Public Power Association - 4 - NA - Not Applicable	
Answer	
Document Name	
Comment	

APPA has multiple concerns with the proposed definition of distributed energy resources (DER) and adding this scope to the MOD-032 Standard, as outlined below.

Scope Expansion and non-NERC Registered Entities

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient to ensure the expansion of scope will be effective or reasonable.

The Technical Rationale states “the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases.” The information includes “Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS,” “Real power capability (minimum and maximum),” “Reactive power capability (minimum and maximum),” “Generator type (solar, battery, etc.),” and “In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.” While DPs may receive some or all of this information at the interconnection request stage, and can pass whatever data they have to their PC and TP, the draft standard must be revised to account for the fact that the DPs and TOs do not own or control these DERs, and thus cannot be held responsible for the completeness or accuracy of the data they themselves receive from the DER owners. For example, a DER owner might inadvertently change its nameplate capacity by replacing a damaged inverter with a different capacity from the original due to supply chain issues, and might not think to inform its DP of the change. More fundamentally, some solar installations, whether commercial, industrial, or homeowners installing on rooftops, do so without taking advantage of net metering or otherwise complying with their distribution utility’s interconnection requirements—in other words, DPs may not have complete information about the *location* of DERs on their systems, let alone the capacity, type, and in-service date. Where customers *do* take advantage of net metering, the metering devices are generally not production meters, which highlights a concern regarding the SDT’s proposal to revise the existing requirement for “aggregate demand” data to state that “For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.” Indeed, it is the nature of “net metering” that the data produced and collected is demand offset by DER output, not separate gross demand and generation values.

A registered entity cannot provide data that the registered entity itself does not have. In particular, it would be unrealistic to expect a TO or DP to have information about unregistered DERs at the same level of detail and accuracy that the unregistered DER owners can provide about their own facilities, nor would it be reasonable to hold a TO or DP responsible for gaps or inaccuracies in the data provided by an unregistered DER owner.

Accordingly, the SDT should, at minimum, revise the proposed standard to indicate that (a) DPs’ and TOs’ responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data’s completeness or accuracy; and (b) the requirement to provide “aggregate demand” can be satisfied by net demand data, at least with respect to net-metered DERs.

Implementation Plan

APPA does not agree with the proposed implementation plan for the DER definition. This definition will eventually be used in several future NERC Standard revisions. Some of these revisions may have a shorter implementation timeframe than Project 2022-02. The effective date of the DER definition needs to be coordinated with the other planned Standard revisions to ensure the timing supports implementation of the other Standard revisions.

Coordination with Other Standard Changes

APPA is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 "NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper." The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences. For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

When reviewing the DER definition, entities need to understand how this definition will be used in all of the impacted Standards. APPA recommends creating a standalone Standards Project that addresses the DER definition development for all future Standard changes, similar to Standard Project 2016-02 and Standard Project 2015-09.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1

Answer	
Document Name	2022-02_Unofficial Comment Form_SRC_07-14-23_Final (as filed).docx

Comment

To achieve this project's objective [1] in an effective and efficient manner, the SRC recommends NERC do the following:

1. **Retain the need to define Distributed Energy Resources (DERs) as part of the scope of this project (as opposed to initiating another project).** This would be beneficial because:

a. The SDT for this project already includes many SPIDERWG members. Therefore, the existing team already has the "right" representation and expertise to perform this task.

b. The existing SDT has discussed and examined a broad range of DER definitions, so a substantial portion of the work needed to develop a DER definition has already been done, thereby giving the existing SDT a leg up on this effort.

c. It would eliminate the need for NERC to initiate another project and for industry to provide representatives to staff another team that would be starting this work from scratch (i.e., a loss of efficiency) and which may not be able to attract a commensurate level of expertise, e.g., SPIDERWG members (i.e., a loss of effectiveness).

2. **Revise the DP registration criteria found in the Rules Of Procedure (ROP), Appendix 5B, Section III** and in the corresponding **ERO Enterprise Registration Practice Guide Distribution Provider "directly connected" Determinations.pdf (nerc.com)** to more closely align with the criteria proposed in its Work Plan to register Inverter-Based Resources (IBRs) under FERC Docket RD22-4-000.

When the DP criteria (RoP, Appendix 5b, Section III.a.1) in the **ERO Enterprise Registration Practice Guide Distribution Provider "directly connected" Determinations.pdf (nerc.com)** was updated in July 2018, two key aspects were modified that are now in direct opposition to the approach NERC is taking with respect to registering IBRs:

a. **The amount of peak load served by the DP system was increased from 25 MW to 75 MW.** This is in direct contrast to NERC's Work Plan for the registration of IBRs whereby NERC is seeking to decrease the registration threshold from 75 MVA to 20 MVA.

b. **The connection point for peak load was changed from "directly connected to the "Bulk Power System (BPS)" to "directly connected to the BES."** Again, this is in direct contrast to NERC's Work Plan for the registration of IBRs whereby NERC is seeking to register IBRs that are directly connected to the BPS.

As the penetration of Distributed Energy Resources (DERs) increases, there will be a reliability need to register a broader range of Distribution Providers as was acknowledged with IBRs. The SRC requests NERC address this issue as part of this project, perhaps as a separate phase.

3. Dual Planning Authority (PA) / Planning Coordinator (PC) Designation

While there is justification to reference both the Planning Authority and Planning Coordinator in the Applicability section (section 4) since NERC Appendix 5B: Statement of Compliance Registry Criteria, dated January 19, 2021, still uses both terms, the explanatory paragraph in Part 4.1.4 refers to synchronization between registration criteria and the NERC functional model, which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the SRC requests the explanatory paragraph be deleted from Part 4.1.4 as illustrated below and in the attached file:

4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

Planning Coordinator (PC) Interface

The SRC notes the importance of retaining the PC's flexibility with respect to determining the process used to acquire modeling data. While some PCs prefer to interface directly with the DP as noted in footnote 2 (*see* page 20 of 22 of the standard), other PCs prefer to interface with the Transmission Owner (TO) or Transmission Planner (TP). In the latter example, the TO or TP maintains the interface with the DP.

Footnote 2: *For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.*

The SRC requests the SDT clarify the required interfaces under the standard are "as directed by the PC" so information flows to the appropriate entities as part of the data collection process. Leave flexibility to the PC for determining how this data is collected as proposed below:

2. Aggregate Demand2 [DP3, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status*

Footnote 2: For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.

Footnote 3: Wherever DP is noted as the functional entity responsible for reporting data in the table, a Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.

Footnote 4: Including synchronous condensers and pumped storage.

Other Clarifications

1. Attachment 1, "steady state" column, item 9

a. Strike "feeder" to provide the TP/PC with flexibility in tracking the status of UVLS and UFLS (i.e. as aggregated values or as individual feeders).

b. Clarify the use of "and/or" with regards to UVLS and UFLS. Using "and/or" creates four possible combinations that must be tracked: UFLS only, UVLS only, Both UFLS and UVLS, and neither UFLS nor UVLS. Is the intent of the SDT to track all these possible permutations?

The SRC requests the SDT modify item 9 to add the following details:

9.a. Location (bus from item 1) and if DER is subject to UFLS and/or UVLS

b. Real power capability (gross minimum and maximum)

c. Reactive power capability (gross minimum and maximum)

2. **Attachment 1, footnote 4 -** clarify the use of "/" as illustrated below:

4 The TP or PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance.

[1] From pages 1-2 of the SAR: "*Update MOD-032-1 to: (1) include "data requirements and reporting procedures" for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.*"

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

General comment: As stated in EEI's response to Question 1, we support the replacement of LSEs with DP, however, Attachment 1 goes beyond the replacement of LSEs with DP and includes TOs as an additional replacement where there are no registered DPs. This change should be stricken from the proposed draft of MOD-032-2. Registration problems cannot be solved through compliance obligations placed on registered entities who do not participate in the approval of DER interconnections or have any ability to compel the sharing of DER data contained on networks outside their purview.

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: Footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed.

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

Answer	
Document Name	

Comment
SMUD and BANC support the comments submitted by APPA, especially with regards to the DER definition and Coordination with Other Standard Changes.

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
Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project: Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”. Delete the 2nd paragraph in section 4.1.4 R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to their PC or TP. Suggesting either adding “written” to R3 or removing it from the R3 VSL. R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…” R2 Severe VSL: Missing the TO entity after the last “OR”. R3 VSL: incorrect references to R4 instead of R3 in all VSL levels. R3 Severe VSL: should read “or within a longer period of 45 days agreed upon by the notifying Planning Coordinator or Transmission Planner” instead of “or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner” TO’s and DP’s cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER’s are not obligated to provide the data. In Attachment 1, under Dynamics, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP) In Attachment 1, under Steady-State, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS

b. Real power capability (minimum and maximum)

c. Reactive power capability (minimum and maximum)

d. Generator type (solar, battery, etc.)

e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control, and/or frequency control.

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

SRP recommends adjusting the definition for the Distribution Provider before making the proposed adjustments so that there is clear delineation of roles and responsibilities.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	
Document Name	

Comment

Eversource recommends the drafting team consider the category of “Transients” (specifically EMT Models) as an inclusion in required data submittals in Attachment 1 to reach the SDT’s goal to “address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments” per the MOD-032 SAR.

While interconnection-wide models are built using dynamic and short circuit studies and not transient studies, there are still situations where border areas are studied between differing TPs or PCs, and the need for these EMT models to be available is necessary to better model aggregate levels of DERs.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	

Attachment 1 Data Reporting table (Steady State Column items 2, and 9, and Dynamics Column items 5, and 10) has added language indicating that the Transmission Owner (TO) is the responsible entity for submitting modeling data when a demand is not associated with a registered Distribution Provider. AZPS requests clarification regarding the type of entity that would have load, but not be a registered distribution provider. AZPS is concerned that the Transmission Owner may not have the ability to produce or acquire certain load information from an unregistered entity unless there is some other type of contractual relationship in place.

Likes 0	
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6	
Answer	
Document Name	
Comment	

Austin Energy supports APPA's comments.

Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy"

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	

Austin Energy supports APPA's comments.

Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy"

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	
Document Name	

Comment

DER Definition:

Southern Indiana Gas & Electric Co. (SIGE) believes the potential impact of the DER definition exceeds the current scope of Project 2022-02 and suggestions expanding the scope of the current project and/or initiating a separate NERC Reliability Standards project to address the DER definition.

Applicability:

SIGE believes there is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. Further clarity on the DER definition is needed.

Attachment 1:

SIGE agrees with EEI's comments that changes to MOD-032-2 should be put on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms intended to address Inverter Based Resources (IBRs) that impact the Bulk Power System (BPS) .

SIGE is supporting EEI's **Footnote 2**.

SIGE recommends replacing the '\' in **Footnote 4** with "**or**". "The TP/ or PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance."

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
Attachment 1 - Under Steady State (2, 9) Recommend changing language to [DP (when a Demand connected to the DP is not associated with a registered DP), TO (when a Demand connected to the TO is not associated with a registered DP)]. Under dynamics (5, 10) Recommend changing language to [DP (when a Demand connected to the DP is not associated with a registered DP), TO (when a Demand connected to the TO is not associated with a registered DP)]. An entity that has an unregistered DP connected to them will have both the knowledge that the entity exists and contacts for them to obtain the required information. If a TO is required to provide information for an unregistered DP that receives its service through a registered DP, they may not know the entity exists or have the required contacts to obtain the required information. As written, the SDT is setting the TO up to fail and be non-compliant. Attachment 1 steady state, modify (9e) to DER capabilities related to ride-through, voltage control and/or frequency control, if available, or In-service date or other information to be used to make assumptions about them if this information is not available. Recommend trying to get the actual information if it is available rather than always making assumptions for this.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	

Comment
Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project: • Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”. • Delete the 2nd paragraph in section 4.1.4 R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to its PC or TP. Suggesting either adding “written” to R3 or removing it form the R3 VSL. R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…” R2 Severe VSL: Missing the TO entity after the last “OR”. R3 VSL: incorrect references to R4 instead of R3 in all VSL levels. R3 Severe VSL: should read “or within a longer period of 45 days agreed upon by the notifying Planning Coordinator or Transmission Planner” instead of “or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner” TO’s and DP’s cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER’s are not obligated to provide the data. In Attachment 1, under Dynamics, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP) In Attachment 1, under Steady-State, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP) a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS b. Real power capability (minimum and maximum) c. Reactive power capability (minimum and maximum) d. Generator type (solar, battery, etc.) e. In-service date or other information to be used to make assumptions about DER capabilities related to ride through, voltage control and/or frequency control.

Likes 0	
Dislikes 0	

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	

Comment
CEHE finds the proposed revisions to MOD-032-2, Attachment 1 too detailed and prescriptive. The NERC Standard should be written to give Planning Coordinators (PC), Transmission Planners (TP) and Transmission Service Providers (TSP) the flexibility to coordinate and determine the specific data requirements that are needed for the planning models under MOD-032-2, Attachment 1. CEHE recommends that data reporting requirements listed in Attachment 1 be determined by the PC, in coordination with TP. In the ERCOT region, processes are already in place to define these data requirements through the coordination of the Planning Coordinator and Transmission Planners as part of various regional working groups. CEHE also supports the comments as submitted by the Edison Electric Institute (EEI) regarding the development of a DER definition separate from the NERC Reliability Standards Project 2020-02. CEHE agrees with EEI comments on how presently, Transmission Owners (TOs) and Distribution Providers (DPs) have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will yield little useful data. Subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represents untenable regulatory obligations they cannot fulfil. To address this concern, CEHE suggests that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operate, be removed. CEHE agrees with EEI comments relative to TOs. These entities may have no insights on DERs of unregistered DP systems and therefore should not be held accountable for supplying this type of information. CEHE supports the additional comments submitted by EEI regarding footnote 4 of the SAR.

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 (EEI) for queston #2.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	
Document Name	

Comment
Southern Company supports comments submitted by EEI on potential implementation challenges.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	

Comment
WEC Energy Group appreciates the opportunity to provide comment and suggests for consideration the inclusion of a specific MW threshold below which DER modeling is not required. WEC Energy Group is also in support of the comments submitted by EEI which state: *"EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.* *We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.* *EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.* *In addition to the above concerns, we offer the following comments and concerns for consideration:* ***Applicability Section*** *There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.* ***Attachment 1*** *Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5* *EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be*

removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: Footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed."

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 at this time.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	
Document Name	

Comment

RF notes the draft standard revision also adds DER data under the steady state and dynamics columns in Attachment 1: Data Reporting Requirements, addressing industry need (1) from the SPIDERWG MOD-032 SAR and appreciates the efforts of the SDT on this project.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1, Group Name National Grid

Answer	
Document Name	

Comment

RE: Definition of Distributed Energy Resource (DER): Please consider that the definition of Distributed Energy Resource (DER) should be more generic, such as, “Real Power and Reactive Power resources connected on the distribution system, in non-isolated parallel operation. Please consider changing active power to Real Power since “active power” is not included in the NERC Glossary of Terms and is in literature a synonym to Real Power and should not be defined differently. In the NERC Glossary of Terms, Real Power is defined as, “The portion of electricity that supplies energy to load.” In the slides presented at the Project 2022-02 webinar (June 27), “Active power” was proposed to “indicate[s] that the scope is focused on only those facilities that may be exporting real power to the power system or offsetting real power load (e.g. residential or commercial rooftop solar, even if they only operate at unity power factor or don’t have any reactive power capability). This would exclude examples such as charging-only electric vehicle (EV) installations and controllable load options.” This proposal seems to indicate active power no longer being used as a synonym to Real Power, which could cause a potential risk of misinterpretations.

RE: Applicability – Functional Entities, Section 4.1.4: Please consider removing the “Planning Authority” function from section 4.1.4 since Planning Coordinator is the preferred function name. Please consider that Project 2017-07 Standards Alignment with Registration was previously removing “Planning Authority” from other standards such as MOD-031-2 and MOD-033-1, in-advance of the removal of “Planning Authority” from Rules of Procedure - Appendix 5B: Statement of Compliance Registry Criteria.

RE: Section C. Compliance: Please consider adding (CEA) as the abbreviation of “Compliance Enforcement Authority” to section 1.1. Please consider using the abbreviation CEA in section 1.2.

RE: Attachment 1: Data Reporting Requirements: Please consider limiting steady-state data for new item 9 to read as, “9. Distributed Energy Resource (DER) data4 [DP]” Please consider that sub-parts a., b., c., d., and e. are not necessary since DER data requirements can be agreed upon per requirement R1.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports the comments of the EEI and the MRO NSRF

Likes 0	

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

We appreciate the SDT's inclusion of a draft definition for a "Distributed Energy Resource (DER)" in Draft 1 of MOD-032-2. We suggest the words 'Generators and energy storage technologies…' in the definition be replaced with 'Sources of Electrical Energy…'. The NERC Glossary of Terms defines "Electrical Energy" as "The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh)" and is technology neutral. While a DER definition is important, the definition in combination with adding DP applicability may not provide the clarity for applicability that the SDT concludes in the Technical Rationale. The SDT should consider whether utilizing a new Facilities applicability section (4.2) could provide further scope clarity.

We believe section 4.1.4 should be updated to simply "Planning Coordinator". This would be consistent with the direction taken in other NERC standards that previously contained similar language regarding PA/PC applicability (see changes made to MOD-031-3 and MOD-033-2 under Project 2017-07, Standards Alignment with Registration). The Project 2017-07 webpage contains the following statement about MOD-032-1:

"MOD-032-1 will not be revised at this time, but may come back into Project 2017-07. The work of the System Planning Impact from Distributed Energy Resource Working Group (SPIDERWG) is ongoing at the time of the final posting for Project 2017-07. In June 2018, the NERC Planning Committee (PC) formed the SPDERWG subcommittee to address Distributed Energy Resource (DER) impacts on the bulk power system (BPS). Currently, the subcommittee has proposed a Standard Authorization Request (SAR) for MOD-032-1 pertaining to DERs. The SAR has recently been reviewed by the PC. At this time, the Project 2017-07 drafting team will not take any action in reference to the MOD-032 standard until the SPIDERWG has completed their initial efforts."

While the Draft 1 Technical Rationale notes that the currently posted "Appendix 5B: Statement of Compliance Registry Criteria" still uses the Planning Authority term, a cursory review of all currently active standards reflects that a transition to "Planning Coordinator" in the applicability sections is almost complete, so making this change in MOD-032-2 would complement this transition. FAC-014-3, effective 4/1/2024, will incorporate the PA to PC change for that standard.

We noted in our comments on the SAR that a Distribution Provider may not always be the most practical source for the DER modeling data needed by the PC and TP. We recognize that the SDT has allowed for the flexibility of a Transmission Owner to also be a source for DER modeling data in Draft 1. However if the DP or TO is not directly affiliated with the DER owner, would their need to collect the DER model data from the entities that possess it not essentially mirror the PC and TP's need under R1? The DP and TO might need their own requirement(s) to develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures to obtain DER modeling data (potentially from unregistered entities that don't have an obligation to comply with NERC's Reliability Standards) that would subsequently be passed on to the PC and TP. A "DER data entity" could also be added to the applicability section (reference PRC-006-5 for precedent) with a broader range of registered entity options to fulfil that role (e.g., DP, UFLS-Only DP, TO, RP, GO).

We interpret the implementation plan to mean that the PC and each of their TPs will have 24 months to jointly update their modeling data requirements and reporting procedures to incorporate the changes in Attachment 1. The entities responsible for providing DER modeling data to the PC/TP will then have 12 months to comply. We believe the initial collection and submittal of DER data will be equally if not more time consuming than the PC/TPs efforts to update their modeling data requirements and reporting procedures. As noted above, after receiving the PC/TP's updated modeling data requirements and reporting procedures, the DER data collectors may need to perform outreach and communicate their own procedure/schedule for receiving the data from others. We suggest the implementation plan be revised to allow 24 months (rather than 12 months) after the effective date for the initial performance of R2, R3 and R4.

We suggest that further development of MOD-032-2 and its associated implementation plan be paused until it can be performed in closer conjunction with NERC's three year plan to register 'GO-IBRs', which is just beginning; and the "Modifications to FAC-001 and FAC-002" Standard Authorization Requests approved for posting at the NERC Standards Committee's May 17, 2023 meeting (no NERC project number assigned yet). Addressing these items (and perhaps other IBR related standards initiatives) in a piecemeal fashion will lead to less optimal results and confusion in the industry.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

PPL NERC Registered Affiliates do not agree with the separate inclusion of DER data in Attachment 1. A lack of specific reference to DER data does not mean that the data does not exist or is not already attainable by PCs and TPs under the existing standard. There are already specific provisions in the Standard allowing for the collection of such data. We do not believe there are gaps or lack of clarity within the currently approved MOD-032-1. Directing how an entity should collect and model such data is overly prescriptive, will increase administrative burden, and limit innovation in modeling DERs. The industry is just now learning how DERs are going to affect the BES. It is counterproductive to circumscribe how entities should meet their compliance requirements.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon concurs with the concerns expressed in the EEI comments.

Requirements for DPs and TOs to provide Aggregate Demand and DER data should be limited to the aggregate data currently available to the entity.

For Attachment 1, Steady-State 9e, we suggest removing the implied requirement for the “in-service dates”. Consider restating Attachment 1, Steady-State 9e as, “Information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.” The Technical Rationale document can be modified to discuss how in-service dates may support the response to Attachment 1, Steady-State 9e.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon concurs with the concerns expressed in the EEI comments.

Requirements for DPs and TOs to provide Aggregate Demand and DER data should be limited to the aggregate data currently available to the entity.

For Attachment 1, Steady-State 9e, we suggest removing the implied requirement for the “in-service dates”. Consider restating Attachment 1, Steady-State 9e as, “Information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.” The Technical Rationale document can be modified to discuss how in-service dates may support the response to Attachment 1, Steady-State 9e.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	
Document Name	

Comment

LES does not agree with the SDT proposed definition of DERs. The definition should be more in line with the FERC Energy Primer definition, already in place.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

The DP must be able to bound restrictions/limitations to TP request due to limited data availability, reasonableness, etc., when DER data requirements are made.

Also, when determining the size of each DER, a minimum size of 500 kVA should be required for inclusion. Anything less than 500kVA would require an onerous amount of effort to provide accurate data, which would result in data being outdated and/or obsolete, etc. There is limited data available (MOD-032-2 Attachment 1) for DP area small DER generation (e.g., residential solar, small commercial), therefore the accuracy of aggregated small DER generation for BES system impact modeling is limited.

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	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	
Comment	

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	
Document Name	
Comment	

1) Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project:

- Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”.
- Delete the 2nd paragraph in section 4.1.4

2) R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to its PC or TP. Suggesting either adding “written” to R3 or removing it form the R3 VSL.

3) R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…”

4) R2 Severe VSL: Missing the TO entity after the last “OR”.

5) R3 VSL: incorrect references to R4 instead of R3 (more specifically R3.2) in all VSL levels.

6) R3 Severe VSL: should read “[...Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response after 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner)” instead of “Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).”

7)TO’s and DP’s cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER’s are not obligated to provide the data.

8) In Attachment 1, under Dynamics, the following change should be made:

- Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

- In Attachment 1, under Steady-State, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS

b. Real power capability (minimum and maximum)

c. Reactive power capability (minimum and maximum)

d. Generator type (solar, battery, etc.)

e. In-service date or other information to be used to make assumptions about DER capabilities related to ride through, voltage control and/or frequency control.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E provides the following:

The MRO New Standard Review Forum (NSRF) has provided additional comments that PG&E wishes to support related to the DER definition. PGAE supports the recommendation that the definition should be removed from this modification and addressed in a separate project since it would impact many Standards currently being worked on or planned for in the future. With seven (7) different DER definitions currently being provided from such sources as the NERC SPIDERWG, NARUC, IEEE, and the California PUC, the Project 2022-02 effort will cause further confusion for the industry.

For this reason, PG&E will be voting Negative for this proposed modification.

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,7 - SERC

Answer	
Document Name	2022-02_Unofficial Comment Form_May2023.docx

Comment
1. Will there be an aggregate DER threshold (either nameplate or net injection to the grid) above which the DP should submit modeling data to the TP and PC for inclusion in transmission planning models? MOD-025, MOD-026, and MOD-027 standards are being revised to limit applicability to resources included in either I2 or I4 of the BES definition (individual units > 20 MVA or an aggregate plant > 75 MVA). Should thresholds for MOD-032 DER modeling be consistent with the other NERC modeling standard applicability thresholds? 2. Will the NERC BES Reference document be revised to include DER generation (individual units and/or DER aggregations)? 3. Are these DER data reporting requirements limited to merchant DER installations in the future only? o It will be challenging to obtain steady-state and dynamic data for each individual installation that has taken place over the years in the past, especially for non-merchant applications (such as residential roof-top solar resources). Hoe are DPs expected to obtain this data and who will bear the cost associated with this process? o How will DPs be able to obtain and verify the in-service dates of each individual distribution connected resource that has occurred in the past? o Most of the residential and other non-merchant solar and battery installations fall below the installed capacity threshold at which such resources are required to go through the distribution interconnection detailed study process. How are DPs expected to collect steady-state and dynamic data on such resources, even if occurring in the future?

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment
Constellation has no additional comments. Kimberly Turco on behald of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters

Answer	
Document Name	

Comment
General comments on MOD-032-2:

a. In Section 4. Applicability, under 4.1.4, BC Hydro recommends that the wording “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)”, be changed to “Planning Coordinator”. Retaining the current wording may create confusion or result in misinterpretation, especially for those utilities that treat PA standards and PC standards differently. A PC-only approach has been used in other recently approved NERC standards and those that are being developed, such as FAC-002-4, MOD-033-2, and MOD-026-2.

b. BC Hydro recommends that in Attachment 1, the language used in the DER steady-state data section (Item 9) be generalized to account for distribution-connected hydroelectric generators. A suggested wording is provided below for consideration:

“…c. Reactive power capability (minimum and maximum)

d. Fuel type (solar, wind, hydraulic, battery, etc.)

e. Generator type (synchronous, inverter-based resource, etc.)

f. In-service date or other …”

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

WECC believes there is value in including these Distributed Sources in system modeling, but is concerned that the proposed defintion may not satisfy that need.

The definition of DER does not seem adequate. First, it includes non BES generation type resources that are beyond BES dispersed generation identified under inclusion I4 of the BES Definition. And thus, appears to go beyond the scope of mandatory standards applicability. A second issue is that because the definition has the qualifier “…connected to the Distribution Provider’s system…” it would leave out any “DER” that did not have a registered Distribution Provider including any connected via some pathway directly to a Transmission System.

WECC believes that a focused effort on defining DER and addressing it within the BES Definition or in the NERC Glossary to be used consistently in all standards.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment
Per the Federal Power Act, NERC's jurisdiction is to establish and enforce Reliability Standards for the Bulk Power System. A NERC document, Understanding the Grid, published in March 2023, indicates that the generation and transmission components and their associated control systems make up the BPS, so requiring DP's to provide DER data that is connected to the Distribution system is outside of NERC's jurisdiction, unless the DER is connected to the transmission system such as non-BES generation. Furthermore, the NERC Glossary of Terms definition for Bulk Power System explicitly states that is does not include facilities used in the local distribution of electric energy, which aligns to the definition for bulk-power system in the Federal Power Act Section 215(a), definitions. DER on a DP's network is not that clear in the Technical Reference document. Please provide some examples similar to the BES reference document of what would not be in-scope DER and what would be in-scope DER on a DP's network. What happens if we are unable to obtain modeling data from OEMs for older DER inverters? What if we do not have the information to determine the collector system impedance values? What happens if residential, retail or commercial owners do not want to support this effort? What happens if an IBR OEM has gone out of business?

Likes 1	Mearns James On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5;
Dislikes 0	

Response

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

Comment
BPA believes that this definition would require adjustment of the BES inclusions and exclusions lists. For example, currently resources below 75 MVA are not required to submit the data that will be required of DER. This will result in entities not providing data for anything less than 75 MVA and citing exclusion (or lack of inclusion), even though the intent appears to require data submission from much smaller resources. BPA suggests excluding legacy equipment such as hydro, or perhaps the definition should only apply to inverter based resources (IBR.) It is also important to note that small generator owners are likely not financially able to test equipment (per MOD-025/026/027) in order to provide modeling data. This could result in shutting down such generators and associated loads costing local jobs in affected areas. BPA requests clarification and consistency regarding the use of Bulk Power System and Bulk Electric System. Both terms are being used.

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 supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

General comment: As stated in EEI's response to Question 1, we support the replacement of LSEs with DP, however, Attachment 1 goes beyond the replacement of LSEs with DP and includes TOs as an additional replacement where there are no registered DPs. This change should be stricken from the proposed draft of MOD-032-2. Registration problems cannot be solved through compliance obligations placed on registered entities who do not participate in the approval of DER interconnections or have any ability to compel the sharing of DER data contained on networks outside their purview.

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As

an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states “TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary”. This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	
Document Name	

Comment

Comments to be supplied separately by AECC's Ayslynn McAvoy.

Likes 0	
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	
Document Name	

Comment

Project 2022-02 is more than the replacement of these registration identifiers as it also includes DER modeling data additions. The question above does not fully encompass the changes proposed for MOD-032-02. However, the changes for adding DER modeling data does seem appropriate and reflects the NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

· Can 4.1.4 be simplified to just Planning Coordinator?

· Note 10 under dynamics in Attachment-1 assumes a specific model for each DER will be provided. Note 9 under steady state (and footnote 4) assume that DER could be aggregated. The dynamics model may also need to be aggregated and there should be a footnote regarding coordination of model parameters. The Resource Planner may need to be involved in the coordination for dynamic models in Years 1-10.

· Regarding the DER definition provided under the section “New or Modified Terms Used in NERC Reliability Standards ”, did the SDT consider the definition provided in IEEE Std 1547-2018, especially Note-1(exclusion of Controllable loads used for demand response) and Note-2 (supplemental DER devices)?

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	

AECI supports comments sumbtted by Tacoma Power.

Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	

No Additional Comments

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; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	

Comment

Tacoma Power has multiple concerns with the proposed DER definition and adding this scope to the MOD-032 Standard, as outlined in the next few bullets.

Scope Expansion and non-NERC Registered Entities

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient on their own to ensure the expansion of scope will be effective.

The Technical Rationale states “the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases.” However, there are large distribution utilities that are not registered as DPs, but have aggregate DERs that should be accounted for under the proposed MOD-032 Attachment 1 scope. To ensure the appropriate entities are held responsible, either the (1) BES definition needs to change to include DERs, (2) a new “DP-DER” registration needs to be created, or (3) the DP registration criteria needs to change to ensure the appropriate entities are held responsible. Of these three options, Tacoma Power recommends revising the DP criteria in ROP Appendix 5B, Section III, to include a new criterion to ensure distribution utilities that must provide data to support MOD-032, Attachment 1, are subject to NERC jurisdiction. This approach aligns with the regulatory precedent set for UVLS programs, RAS schemes, and Protection System components under PRC-005 and PRC-006. Without a seperate effort to revise the DP registration, Tacoma Power cannot approve the draft MOD-032. The draft Standard cannot be fulfilled without these entities being held responsible for the data.

Below is an example mark-up of ROP Appendix 5B, Section III for NERC to consider in the ROP revision:

III.a.1 Distribution Provider system serving >75 MW of peak Load that is directly connected to the BES; or

III.a.2 Distribution Provider is the responsible entity that owns, controls, or operates Facilities that are part of any of the following Protection Systems or programs designed, installed, and operated for the protection of the BES:

- *a required Undervoltage Load Shedding (UVLS) program and/or*
- *a required Special Protection System or Remedial Action Scheme and/or*
- *a required transmission Protection System; or*

III.a.3 Distribution Provider that is responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs) pursuant to an executed agreement; or

III.a.4 Distribution Provider with field switching personnel identified as performing unique tasks associated with the Transmission Operator’s restoration plan that are outside of their normal tasks; or

III.a.5 Distribution Provider is the responsible entity that serves, controls, owns, or operates Distributed Energy Resources (DERs) exceeding 0.01 MW.

DER Definition

Tacoma Power supports the essence of the DER definition, but is concerned that it is unclear whether the proposed definition includes devices that have transient export of real power such as closed transition transfer switches, regenerative elevators/cranes, and industrial motors with regenerative braking. The proposed definition should be clarified to exclude these devices, while still including devices installed for energy storage such as batteries, flywheels, and Synchronous condensers. Tacoma Power suggests adding "for at least 30 seconds" to the definition so that the definition reads "... *providing active power for at least 30 seconds in non-isolated parallel operation*... "

The IEEE definition of DER includes both the energy resource plus any necessary supplemental equipment. Tacoma Power would like to see similar guidance within the NERC DER definition. This ensures that reactive power control devices such as capacitor and STATCOMS are correctly included in the DER model submittals.

Implementation Plan

Tacoma Power does not agree with the proposed implementation plan for the DER definition. This definition will eventually be used in several future NERC Standard revisions. Some of these revisions may have a shorter implementation timeframe than Project 2022-02. The effective date of the DER definition needs to be coordinated with the other planned Standard revisions to ensure the timing supports implementation of these other Standard revisions.

Coordination with Other Standard Changes

Tacoma Power is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 "NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper." The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences. For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

When reviewing the DER definition in this posting, entities need to understand how this definition will be used in other future Standard changes. Tacoma Power recommends one of the two following options to ensure impacts to other future Standard changes are considered in the definition development:

1. Provide a list of other Standards that will be impacted by this definition change in the "New or Modified Term(s) Used in NERC Reliability Standards" section of the MOD-032 redline, similar to the approach taken by Project 2019-04, Modifications to PRC-005, or
2. Create a standalone Standards Project that addresses the DER definition development for all future Standard changes.

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	
Document Name	
Comment	
SMEs responded "MOD-032-1 provides language for the Planning Coordinators (PC) and their Transmission Planner(s) (TP) to request any, and all, modeling data pertaining to the development of steady-state, short circuit, and dynamics models. The language in MOD-032-1 currently allows the PCs and TPs to request DER data from TOs, GOs, and LSEs (Distribution Providers). Therefore, any language specific to the addition of DERs to MOD-032-1 would be redundant."	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
EEI Draft Comments should be included or referenced: {C}· {C}To better clarify the extent of DER resources that must be reported under MOD-032, EEI suggests that a Facilities section be added to this Reliability Standard. {C}· {C}Footnote 2 – EEI asks that the SDT provide additional clarity regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While we understand why this would be desirable, most small DERs are not metered except for billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. We are further concerned that the manhours required to account for these DER offsets could be substantial adding excessive costs while providing questionable value to this change. As an alternative, EEI suggests that DPs and TOs could provide estimated DER offset values, which would require fewer manhours to develop and should provide sufficient value to the planning models. {C}· {C}Steady-state and Dynamic columns EEI is concerned that the data requests identified in Item 9 (Steady-state), and Item 10 (Dynamic) seek non-aggregated data, while the SAR specifies that aggregated DER data is to be supplied. To address this concern, we ask that both Items 9 and 10 be edited to make it clear that data requests to DPs and TOs are to be limited to aggregate DER data.	

Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states “TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary”. This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	2022-02 Tables.PNG

Comment

- The NSRF recommends the SDT remove the DER definition from the proposed MOD-032-2 standard.

- The NSRF recommends NERC create a standalone Standards Project that addresses the DER definition development for all future Standard changes. As part of this project, the NSRF recommends revising the DP criteria in the Rules Of Procedure (ROP), Appendix 5B, Section III.

- NERC needs a way to register a DER or “DER aggregator” type entity, to ensure the appropriate entities are held responsible for NERC Reliability Standards.

Further:

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient to ensure the expansion of scope will be effective.

Currently there are seven definitions for DER. The SDT chose to create a new definition of DER separate from those.

The proposed definition:

Term(s): Distributed Energy Resource (DER) Generators and energy storage technologies connected to the Distribution Provider’s system that are capable of providing active power in non-isolated parallel operation with the Bulk Electric System.

The SPIDERWG Terms and definitions document has six definitions for DER. The draft MOD-032-2 definition is different than the definitions contained in the document. See Table D.1: Alternate Definitions for DER-Related Concepts.

Link to SPIDERWG Terms and definitions document

Link to DER reference document – contains DER definition.

Distributed Energy Resources Connection Modeling and Reliability Considerations February 2017

The NERC Distributed Energy Task Force (ERTF) DER definition:

“Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).”

The NSRF is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 “NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper.” The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences.

For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

The Technical Rationale states “the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases.” However, there are large distribution utilities that are not registered as DPs, but have aggregate DERs that should be accounted for under the proposed MOD-032 Attachment 1 scope. To ensure the appropriate entities are held responsible, either the:

1. BES definition needs to change to include DERs,

2. a new “DP-DER” registration needs to be created, or

3. the DP registration criteria needs to change to ensure the appropriate entities are held responsible.

From the SPIDERWG Terms and Definitions Working Document:

-See Attachment

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
NIPSCO agrees with the comments of the Edison Electric Institute (EEI) regarding the proposed TPL-001-5 Footnote 13d revision.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP appreciates the efforts of the standards drafting team and sees the value of the proposed revisions to Attachment One. Even so, AEP would be unable to vote affirmative on this revised standard unless and until every entity providing DER data is a registered Functional Entity who is formally obligated to provide it. As is the case in existing standards where Generator Owners are obligated to provide similar data, entities who possess the needed DER data noted in the Attachment One revisions should likewise be registered and explicitly obligated to provide this data as well. While we are unsure if the existing Functional Entities classes are themselves sufficient, or if instead, a new class of Functional Entities might need to be considered and developed, the need nonetheless exists. NERC may wish to also consider the potential that such obligations could potentially cross Federal and State jurisdictional lines of responsibility, further illustrating the complexity-of and challenges-in developing obligations to obtain the DER data in the revised Attachment One. In addition, while the SDT has not provided a question regarding the proposed Implementation Plan, AEP believes additional time will be needed to accommodate the work pertaining to assets newly brought into scope. Rather than being required to comply with the obligations 12 months after the definition has become effective, we instead suggest it be 24 months after the definition has become effective.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	
Document Name	
Comment	

The Project 2022-02 SDT should review and coordinate with ERO efforts separately filed with FERC in the NERC proposed work plan to register GO-IBRs. Recognizing the current and expected state of DER and inverter-based resources in North America demands that any revisions proposed to the MOD-032-2 Reliability Standard respect functional registrations and corresponding cognizance of modeling data.

Likes 0	
Dislikes 0	

Response

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 - MOD-032-2
Comment Period Start Date:	5/31/2023
Comment Period End Date:	7/14/2023
Associated Ballot(s):	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan IN 1 OT 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 IN 1 ST 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 IN 1 NB

There were 77 sets of responses, including comments from approximately 200 different people from approximately 126 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 to remove "Load Serving Entity" and replace with "Distribution Provider" in MOD-032-2?**

2. **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

1. Do you agree with the modification to remove "Load Serving Entity" and replace with "Distribution Provider" in MOD-032-2?	
Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	No
Document Name	
Comment	

To be clear, the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change is incomplete, misappropriates modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data, as well as retains a significant reliability gap.

Transmission Owners who are not Distribution Providers likely have no knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. Transmission Owner visibility for load demand is typically limited to historical telemetered MW and MVAR data. This finding, especially with regards to DERs, has already been well-documented. A key recommendation in the NERC Reliability and Security Technical Committee (RSTC) subcommittee approved the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was:

"TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements or practices that will ensure this data is available. ***As the TPs, PCs, and TOs are dependent on the DP to have the data made available****, this will likely require actions from state regulatory bodies and DPs to establish requirements to gather this information" (page 7 of 61).*

The SDT should consider that Transmission Owners should not be held accountable for demand and DER data that they have no cognizance of. Additionally, the SDT should remember that most DER are smaller than the BES resource threshold or reside on a distribution system. The threshold for an entity to be registered as a Distribution Provider is 75 MW of load. This implies that the majority of DERs are and will be connected to systems outside the scope and visibility of Transmission Owners, as well as existing Distribution Providers. To emphasize this reality: as of 15 May 2023, there were 314 Distribution Providers registered with NERC (excluding UFLS-only DPs). Of those DPs, 96 were not otherwise registered as either a PC, TP, or TO. While it may be misunderstood that only 96 DPs may become newly

applicable and participatory in model data collection given the draft changes to MOD-032-2, this ignores that the latest EIA 861 data (collected in 2021; published in 2022) reflects about 1,190 distribution utilities reflecting almost 197,000 distribution circuits in the continental US. In other words, it may be reasonable to conclude that 74% of the distribution utilities in the US do not meet the NERC registration threshold. Furthermore, PCs, TPs, and TOs have no regulatory relationship with these unregistered entities and cannot be held responsible for DER data for which that are not aware.

In June 2022, NERC published its "Inverter-Based Resource Strategy" that recognized efforts necessary to analyze the breakdown of resource size, location, type, and applicability with the BES definition to make a determination of whether the current BES threshold should be updated to reflect the changing resource mix" (page 9 of 10). Subsequently, the NERC Member Representatives Committee (MRC) and Board of Trustees (BOT) technical session on inverter-based resources in February 2023 emphasized the need for a focus on functional registration noting: "industry is increasingly challenged with addressing reliability issues for unregistered inverter-based resources, and those resources are reaching critical mass in some parts of the country. The lack of requirements currently imposed on those resources creates local and regional reliability risks to the BPS in aggregate. This issue compounds in many areas with the growing presence of distributed energy resources (DERs) connected to the distribution system." In response to the FERC directive "Registration of Inverter-based Resources", NERC filed a proposal to modify its Rules of Procedure to "include a new function comprised of owners of IBRs interconnected to the BPS." The Generator Owner – Inverter-Based Resource (GO-IBR) registration would include "owners of IBRs which have aggregate nameplate capacity of less than or equal to 75 MVA and greater than or equal to 20 MVA interconnected at a voltage greater than or equal to 100 kV; or Owners of IBRs which have aggregate nameplate capacity of greater than or equal to 20 MVA interconnected at a voltage less than 100 kV."

Given the anticipated GO-IBR functional registration, the NERC Project 2022-02 SDT should modify MOD-032-2 Attachment 1 to specify **DP, GO-IBR** are responsible for Aggregate Demand, Demand, and Distributed Energy Resource (DER) data, as well as other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

Thank you for your comment.
The SDT views comments suggesting NERC registration of individual DER owners as unnecessary and impractical (similar to the impracticality of registering the load at every single house connected to the system) that would still require DPs and TOs to report what is connected to their systems unless NERC registration of every single rooftop solar installation is being proposed.

The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

GO-IBR
The SDT is unable to add a registration not currently defined in the NERC registration documents. Further the proposed GO-IBR registration would not cover many DER installations.

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
Comments to be supplied separately by AECC's Ayslynn McAvoy.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to AECC.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No

Document Name	
Comment	

WECC supports the removal of Load Serving Entity as that registration no longer exists. However, WECC believes that adding Distribution Provider is not necessary as explained below.

Including the registered Distribtuion Provider in the applicability of the standard complicates compliance applicability and monitoring. It requires two processes and two monitoring mithods instead of one.

The technical rational for the standard states that for distribution facilities which have no Distribution Provider, or which do not connect to a Distribution Provider, the Transmission Owner is responsible for coordinating to obtain the necessary data. If the TO can perform this for distrbution facilities that do not have a registered DP, they can use the same process to obtain the data from a registered DP.

This removes the need of potentially complex determination of standard applicability and the research needed to determine applicability for each Transmission Owner based on the existence of registered Distribution Providers or any other non-BES load that has no registered DP. It also makes clear that the Planning Coordinator and Transmission Planner would be receiving bus level demand data from a single source (The Transmission Owner) rather than obtaining data from multiple DP's and TO's.

If there is a concern that without a standard requirement to support it, a registered DP would not provide the required data to a TO or TP then how could it be expected that a non-registered entity would provide this information. The TO has the authority to obtain this data for any entities connected to its system via FAC-002.

If it is decided to continue to include Distribution Providers in the applicability, please clarify the applicability and obligation of the "registered" (USLF)- Only DP. Would MOD-032 now be applicable to all USLF only Distribution Providers?

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. Data flow processes Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. It should be clear that UFLS-only DPs are not included in the Applicability.

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	
The definition of Distribution Providers is limited by the current definition of Distribution providers to the entity that operates the wires between the Transmission system and the end-user. This is a short-cut to getting the DERs included in the standard. I recommend editing the definition of Distribution Provider to include those entities that are responsible for the operation and balancing of DERs if this is how the SDT wants to address this issue.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Modifying the definition of Distribution Provider is beyond the scope of this project.	

Thomas Standifur - Austin Energy - 1	
Answer	No
Document Name	
Comment	
Austin Energy supports APPA's comments. Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

LCRA notes that the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change inappropriately assigns modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data. Transmission Owners who are not Distribution Providers likely have limited knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. This finding, especially with regards to DERs, was identified in the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer

Answer	No
Document Name	

Comment

Oncor does not agree with the Load Serving Entity ("LSE") to Distribution Provider ("DP") terminology modification. Even for Transmission Owners that are also DP (like Oncor), there are many instances in which we interconnect and deliver transmission-level service to another DP. In these cases, Oncor would not have access to the DER modeling parameters listed in Attachment 1 or visibility into the other DP's system other than the aggregated load provided.

We further disagree with the changes outlined in Attachment 1 in the Steady-State column of Table – #9, which are being proposed in conjunction with the change in terminology from LSE to DP. It will be more appropriate to specify general model requirements in MOD-032 and allow Planning Coordinators and Transmission Planners to determine model details that are appropriate for their established processes and methodologies. Also, it may be impossible to provide individual specifications for Retail Scale DER such as reactive capability and in-service date.

Also, Oncor would like further clarification on the following:

1. "a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS"
    - Could the SDT elaborate on how knowing that a DER is on a UFLS feeder could impact the results of a Steady State analysis? We do not see the need for the UFLS data in the Steady State column.
2. "b. Real power capability (minimum and maximum)"
    - Is this referring to the nameplate or approved capacity?
    - Is the meaning of *minimum* equivalent to approved capacity? And is *maximum* equivalent to nameplate capacity?
3. "c. Reactive capability (minimum and maximum)"
    - Oncor does not typically track reactive power data for currently installed DER.
4. "d. Generator type (solar, battery, etc.)"
    - Oncor recommends modifying this statement to give instruction on how to report a single location with multiple types of DER.
5. "e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control."
    - Can you define the in-service date? In Oncor's experience, some DER projects will connect to our system, test, and then permission is granted to operate. For some of the DER projects, we give permission for them to operate; but the project is not energized until the DER facility is ready on their end. Typically, the registered resources that participate in ancillary services go in-service before they are permitted to operate for testing purposes.
    - This is not practical for DERs that are modeled in an aggregated manner.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. Adjustments made to Attachment 1 – many identified items would be specified in PC/TP procedures. Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1.	
Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins	
Answer	No
Document Name	
Comment	
LCRA TSC notes that the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change inappropriately assigns modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data. Transmission Owners who are not Distribution Providers likely have limited knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. This finding, especially with regards to DERs, was identified in the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical	

Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
A specific definition of DER should be included in the standard. A specific MW threshold for the inclusion of a DER in the interconnected transmission system model data should be included in the standard	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. A NERC Glossary definition for DER was proposed.	

DER MW thresholds NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FE supports the removal of “Load Serving Entity” and supports the addition of “Distribution Provides” in MOD-032-2.	
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	
Load Serving Entity is no longer an active NERC registration code. BPA agrees that replacement is appropriate. However, Attachment A adds a parenthetical that states the Transmission Owner (TO) is responsible when a Demand or DER is not associated with a registered DP. That would put the responsibility on BPA as the TO. What if the TO cannot get non-BES DER data from an	

unregistered customer? As long as BPA is held responsible for providing data as the TO (that we do not have the authority to require from an unregistered DP), our vote will be NO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behald of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,7 - SERC	
Answer	Yes
Document Name	2022-02_Unofficial Comment Form_May2023.docx
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the modification to remove the “Load Serving Entity” (LSE) and replace it with ‘Distribution Provider” (DP) since the LSE designation has been retired.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	

Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to NPCC/RSC.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to MRO NERC Standards Review Forum (NSRF).	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation has no additional comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the removal of Load Serving Entities (LSE) and the addition of Distribution Providers (DP) as an appropriate LSE replacement.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the removal of Load Serving Entities (LSE) and the addition of Distribution Providers (DP) as an appropriate LSE replacement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports the comments of the EEI	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. See response to EEI.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Yes, this change will be helpful in obtaining DER data for transmission planning studies	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Agree with EEI comment: {C}· To better clarify the extent of DER resources that must be reported under MOD-032, EEI suggests that a Facilities section be added to this Reliability Standard. {C}· Footnote 2 – EEI asks that the SDT provide additional clarity regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While we understand why this would be desirable, most small DERs are not metered except for billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. We are further concerned that the manhours required to account for these DER offsets	

could be substantial adding excessive costs while providing questionable value to this change. As an alternative, EEI suggests that DPs and TOs could provide estimated DER offset values, which would require fewer manhours to develop and should provide sufficient value to the planning models.

{C}· Steady-state and Dynamic columns

EEI is concerned that the data requests identified in Item 9 (Steady-state), and Item 10 (Dynamic) seek non-aggregated data, while the SAR specifies that aggregated DER data is to be supplied. To address this concern, we ask that both Items 9 and 10 be edited to make it clear that data requests to DPs and TOs are to be limited to aggregate DER data.

{C}· Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The SDT determined that a Facilities section is not necessary. Modifications were made to clarify data obligation for TOs and DPs with respect to data related to DER, for which a definition is proposed.

The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and

BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. Modifications to footnotes 2 and 4 are intended to address the concern and emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comment of EEI which states: *"EEI supports both the removal of Load Serving Entities (LSE) and the addition of Distribution Providers as an appropriate LSE replacement."*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports comments submitted by EEI.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for queston #1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) is supporting the proposed MOD-032-2 modification to replace Load Serving Entities (LSE) with Distribution Providers (DP).	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric Co. (SIGE) is supporting the proposed MOD-032-2 modification to replace Load Serving Entities (LSE) with Distribution Providers (DP).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
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 both the removal of Load Serving Entities (LSE) and the addition of Distribution Providers as an appropriate LSE replacement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1	
Answer	Yes
Document Name	
Comment	
The The **ISO/RTO Council Standards Review Committee ("SRC")** [1] supports the replacement of "Load Serving Entity (LSE)" with "Distribution Provider (DP)." This is a vast improvement over where MOD-032 stands today as this will fill the gap left by the retirement of the LSE function. [1] For purposes of these comments, the IRC SRC includes the following entities: CAISO, IESO, ISO-NE, MISO, NYISO, PJM, SPP and ERCOT (with the exception of the response to question 2).	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; - James Mearns	
Answer	Yes
Document Name	
Comment	
This modification appears to meet the intent of the SAR by addressing the paralleled DERs that are presently not modelled within Distribution Provider's system models. While some argument could be made concerning the minimal impact on system planning studies caused by Distribution Customer's DER deployment, it is important to set a standard approach toward assessing potential impacts, and these requirements are not substantially burdensome.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
For this response, ERCOT joins the comments submitted by the ISO/RTO Council Standards Review Committee and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to ISO/RTO Council Standards Review Committee.	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Allete - Minnesota Power, Inc. - 1 - MRO	
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.	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, 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	
Thank you for your support.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
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.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you 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	
Thank you for your support.	
Imane Mrini - Austin Energy - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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.	
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	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Desmarie Waterhouse - American Public Power Association - 4 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
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.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
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 supports the modification to remove Load Serving Entity (LSE) and replace with Distribution Provider (DP) as LSE is no longer a registered function. Texas RE has some concerns, however, regarding the actions required by the DP in gathering Distributed Energy Resource (DER) data. There seems to be a potential gap for getting the DER data for Power System Modeling and Analysis as written. DPs are not typically the owners of the DER data and there are no current NERC registration or requirements for the owners of the DER data to provide the data to DPs. As written, the compliance responsibility for providing the DER data falls on the DP who may not authority or a robust process to get the data from the current and future DER owners. Texas RE recommends a requirement that the registered entity managing DERs provide the data to the DPs. Additionally, that non-registered DERs should be captured effectively to ensure reliability operations.

Texas RE does agree that the DPs should be responsible for providing the equivalent system impedance data (distribution feeder, power transformer, etc.) for the DER connections.

The Standard does not specify a threshold limit for the DER facilities required to provide the data. Texas RE recommends the 'Term(s)' section include a distinction between utility scale DERs (commercial level DERs, utility scale solar facilities, etc.) and aggregated level DERs (residential rooftop solar, small generators, residential batteries, etc.).

Texas RE understands the intention of the modifications to MOD-032 is to provide visibility of DER in planning models and achieve consistency in representation of various types of DER. To avoid double-counting DERs in the models, Texas RE recommends identifying whether or not the DER outputs are embedded in the load forecasts used in the models and that this is aligned with the demand and energy data that is needed for MOD-031-3.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

DER MW thresholds
NERC has recommended a zero MVA threshold for gathering DER information:
https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02.

2. Provide any additional comments for the standard drafting team to consider, if desired.	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	
In lieu of creating yet another definition, we recommend using one of the existing definitions in Table D.1 of the SPIDERWG document: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf, or potentially using the NERC Distributed Energy Task Force (ERTF) DER definition: Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom	
Answer	
Document Name	
Comment	
Buckeye agrees with the comments prepared by ACES:	

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may or may not have a material impact to the reliability of the BES. Additionally, we have concerns regarding footnote 4 on the last page of the Attachment 1. This footnote states: "The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance." This statement seems to allow some discretion for allowing "local practices" to then dictate what classifications of DER are to be modeled in aggregate versus otherwise. If that is the case, then it seems to conflict with the stated goal of the MOD-032-1 SAR to "…provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data." We recommend that a non-zero MVA threshold be established below which DER data will be modeled in aggregate and above which DER data will be modeled explicitly. Allowing such "local practices" to dictate which DERs are to be modeled in aggregate or not seems contrary to having a standard for the industry to implement that is intended to provide clarity and consistency. Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
NERC has recommended a zero MVA threshold for gathering DER information:
https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02.

Footnote 4 modified to address the concern. The SDT intent is to maintain PC/TP flexibility for consistently collecting accurate data, but not be overly prescriptive on data collection processes.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	2022-02_Unofficial Comment Form_ERCOT Comments.docx
Comment	

ERCOT generally supports DER-related data collection and recommends that it occur at an early stage (steady-state) of model development. ERCOT requests the following revisions and clarifications to the draft standard.

1. Dual Planning Authority (PA) / Planning Coordinator (PC) Designation

While there is justification to reference both the Planning Authority and Planning Coordinator in the Applicability section (section 4), since Appendix 5B: Statement of Compliance Registry Criteria of the NERC Rules of Procedure, dated January 19, 2021, still uses both terms, the explanatory paragraph in Part 4.1.4 refers to synchronization between registration criteria and the NERC functional model, which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, ERCOT requests the explanatory paragraph be deleted from Part 4.1.4, which would then read as follows:

4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

2. Planning Coordinator (PC) Interface

ERCOT notes the importance of retaining the PC's flexibility with respect to determining the process used to acquire modeling data. While some PCs prefer to interface directly with the DP as noted in footnote 2 (*see* page 20 of 22 of the standard), other PCs prefer to interface with the Transmission Owner (TO) or Transmission Planner (TP). In the latter example, the TO or TP maintains the interface with the DP.

In support of this flexibility, ERCOT requests the SDT revise the table in Attachment 1 by removing the last sentence from footnote 2, adding a new footnote 3 to the first reference to DP in the steady-state column, and renumbering the remaining footnotes as needed, as proposed below:

2. Aggregate Demand*2* [DP*3*, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status*

Footnote 2: For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.

Footnote 3: Wherever DP is noted as the functional entity responsible for reporting data in Attachment 1, a Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

3. Attachment 1, *steady state* column, item 9

a. Strike "feeder" to provide the TP/PC with flexibility in tracking the status of UVLS and UFLS (i.e. as aggregated values or as individual feeders).

b. Clarify the use of "and/or" with regards to UVLS and UFLS. Using "and/or" creates four possible combinations that must be tracked: UFLS only, UVLS only, both UFLS and UVLS, and neither UFLS nor UVLS. Is the intent of the SDT to track all these possible permutations?

ERCOT requests that the SDT modify item 9 to read as follows:

9.a. Location (bus from item 1) and if DER is subject to UFLS and/or UVLS

b. Real power capability (gross minimum and maximum)

c. Reactive power capability (gross minimum and maximum)

4. Attachment 1, existing footnote 4 - clarify the use of "/" by revising the footnote to read as follows:

4 The modeling data requirements and reporting procedures that the PC and TP jointly develop under R1 may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance.

5. Clarify the intent of the short circuit column

The technical rationale states that "[d]rastically altering the structure of Attachment 1 or adding DER data to the 'short circuit' column was beyond the scope of the Project 2022- 02 SAR," which in turn states "note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states 'all applicable elements' in the steady-state column should have necessary information

related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently."

While the dynamics column was edited to include Distributed Energy Resource Data to match the format of the Dynamics column, the short circuit column was not updated per the reasoning given in the technical rationale and SAR. However, the short circuit column includes the bullet "[p]rovide for all applicable elements in column 'steady state' [GO, RP, TO]," which could be interpreted to compel the relevant entities to collect DER information in the short circuit models if it is deemed an applicable element. ERCOT requests that the SDT confirm that the TP/PC would determine if DER information is an applicable element for short circuit models.

6. Clarify the note regarding data that vary with system operating state and conditions

The steady-state column of Attachment 1 indicates that "[i]tems marked with an asterisk indicate data that vary with system operating state or conditions." ERCOT recommends that the SDT clarify or provide additional information regarding what types of system operating states or conditions are contemplated. For example, if a data element changes seasonally, should the element be marked with an asterisk, or are seasonal variations not considered "system operating state[s] or conditions" for purposes of Attachment 1?

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Change made to address PC/PA applicability.

Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale.

The intent of the SDT is to track all of the identified permutations of UFLS and UVLS.

Changes made to item 9 to address the concern and provide PC/TP flexibility.

Technical Rationale modified to address concern about short circuit column. Regarding asterisks – this is outside the scope of the SAR. The SDT does not believe asterisks would apply to any of the new items added.
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment
We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may or may not have a material impact to the reliability of the BES. Additionally, we have concerns regarding footnote 4 on the last page of the Attachment 1. This footnote states: "The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance." This statement seems to allow some discretion for allowing "local practices" to then dictate what classifications of DER are to be modeled in aggregate versus otherwise. If that is the case, then it seems to conflict with the stated goal of the MOD-032-1 SAR to "…provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data." We recommend that a non-zero MVA threshold be established below which DER data will be modeled in aggregate and above which DER data will be modeled explicitly. Allowing such "local practices" to dictate which DERs are to be modeled in aggregate or not seems contrary to having a standard for the industry to implement that is intended to provide clarity and consistency. Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. Footnote 4 modified to address the concern. The SDT's intent is to maintain PC/TP flexibility for consistently collecting accurate data, but not be overly prescriptive on data collection processes.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	

The SPP RTO recommends the drafting team revise the original Standard Authorization Request (SAR) to keep the project open and coordinate with other NERC drafting teams to address data collection efforts that are applicable to the Inverter-Based Resource (IBR) and Energy Storage Resource (ESR-Batteries). This coordination effort will create a level of proficiency and efficiency in the areas of creating accurate models that can be used by the appropriate entities in their study processes to generate quality results that address initial concerns applicable the reliability of the grid.

The drafting team should conduct a cost analysis to help industry understand the cost impacts of this project.

Additionally, the drafting team should consider a resource analysis to help industry understand the additional time required for their resources to participate in these efforts if the project is extended for a certain amount of time.

As for concerns, one of them focuses around NERC suggesting new responsibilities being applicable to the PC and TP in reference to modeling as well as studying process in reference to the reliability of the grid. For example, NERC suggests that there is a need to conduct an EMT study ever so often to help identify issues in a PC and TP footprint; however, the EMT standard has not been approved by the NERC Board of Trustees (BoT) nor FERC at this point. The RSTC has identified that the MOD-032 standard current doesn't align with such data collection

efforts to assist industry, specifically the PC and TP, in this type of process. These data collection gaps need to be resolved prior to giving the PC and TP related responsibilities.

Furthermore, there will be a need to align with the proposed MOD-026-2 standard in reference to the IBRs from a PC and TP perspective (PC and TP creating a process for GOs and TOs to access models).

Moreover, NERC has identified that PRC-024-3 doesn't provide the information needed to address IBR ride-through with the occurrence of a system disturbance. From our perspective, there will be a need for data collection via MOD-032 to help ensure an appropriate performance standard can be developed to address NERC's reliability concerns and needs.

Finally, our last concern pertains to the definition of the DER. There are several definitions currently used in industry, including the SPIDERWG's definition. We recommend that the drafting team coordinate with NERC legal to structure one definition (vetted via standard development process) for industry use. Without a common Glossary Term, there is a potential that the various definitions of DER will create confusing as well as reliability/compliance risks for the PC and TP..

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Establishing EMT modeling and data requirements for DER is beyond the scope of Project 2022-02.

MOD-026 is currently only applicable to BES facilities. There would need to be a separate project to add DER applicability to MOD-026.

PRC-024 - The SDT feels the language in Attachment 1 is appropriate to address the concern.

DER definition
The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	

Document Name	
Comment	

Taunton Municipal Lighting Plant (TMLP) understands and respects the defined need for additional DER modeling data as these resources continue to grow behind-the-meter and beyond the visibility of PCs and BAs. Our concerns with the modifications to MOD-032 are simply to ensure that they require what we can reasonably expect to provide given current configurations. Adding all of the changes that the SDT proposed concerns us that we will continue to add costs to these projects and continue to prevent their viability. Below are additional comments on a few specific proposed revisions to MOD-032:

Proposed DER Definition: The project team is proposing to define a new term of DER to the NERC Glossary. We request additional clarity and background on the development on this definition. We have reviewed the Technical Rationale document that explains its development on Page 1, but it still remains unclear to us what could be considered to have "parallel operation" with the BES versus being a non-BES asset. TMLP requests that we consider a definition that better aligns with the BES definition and its inclusions/exclusions as this will be better understood by DPs.

Att. 1, Steady State Column, New Item 9: The request to provide real and reactive capability, as well as generator type, is within reason as it is readily available information.

Att. 1, Dynamics Column, New Item 10: TMLP requests additional clarity on the parenthetical that requires a distinction of an "*association*" between the DER and the DP, without which the TO is expected to be responsible. In either scenario, it will be unreasonable to expect the DP or TO to provide dynamic modeling information of the DERs. Currently, the DP is typically the host through a Power Purchase Agreement but are not requiring that DER developers provide dynamic modeling information, and the added cost to do so must be considered. At a minimum, the SDT should limit any TO/DP obligations to what is feasible and reasonable, and presently dynamic information for unregistered DERs is not available to us (as a DP) and other DP peers. Expecting a DP or TO to provide this information would require them to alter their interconnection agreements for future projects, as well as sending them on a "research mission" for their existing resources. Further on this point, TMLP agrees with APPA's comments which state "*While DPs may receive some or all of this information at the interconnection request stage, and can pass whatever data they have to their PC and TP, the draft standard must be revised to account for the fact that the DPs and TOs do not own or control these DERs, and thus cannot be held responsible for the completeness or accuracy of the data they themselves receive from the DER owners.*"

tt. 1, Steady-State Column, Footnote 2 on "Aggregate Demand": This effectively provides the authority for the host PC/TP to request that DPs reconstitute their load readings prior to submitting, however, the DP's typically are not using revenue quality metering with their DERs

and therefore cannot be relied upon for market reporting. If this is not the intended use of the data, then this needs to be clarified in this footnote. The Technical Rationale document states that current collection and modeling of net demand is not consistent with "a modeling framework that explicitly represents DER," and if this is true, then we need to understand what this framework is. We reside in ISO-NE and their market rules currently define the inputs to *Regional Network Load* to exclude "load served by behind-the-meter generation" (ISO-NE OATT, Section II.21.2).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale. Improper DP/TO applicability The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. Aggregate Demand The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale.	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	
Document Name	
Comment	

In addition to PJM supporting the IRC SRC comments, PJM wants to ensure the coordination of Distribution Provider (DP) data is coordinated between the DP and Transmission Owner (TO). The coordination between the DP and TO is needed to properly model due to the DP interconnection with the TO. Thus, each Transmission Owner shall work with the Distribution Provider(s) within the Transmission Owner's area in collecting data for the PA and PC in order to properly model this information and how it interconnects with the Transmission Owner systems. PJM is requesting this information to be written directly in the Standard to ensure accurate and proper data collection. PJM wants to the thank the Standard Drafting Team for all their work and commitment to the Project!	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The changes made to Attachment 1 in conjunction with R1 address this concern. Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6	

Answer	
Document Name	
Comment	
For the dynamics column in Attachment 1, it is unclear as to what DER data may be requested from the DP. Seminole recommends the drafting team to provide additional clarification, similar to what the dafting team provided in the steady state column, for the data to be collected in the dynamics column.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. It is expected that much of the same data listed under the steady-state column would be needed for dynamics. MOD-032-2 provides the PC/TP flexibility in developing joint modeling data requirements and reporting procedures per R1. Modifications were made to Attachment 1 to address the comment.	
Desmarie Waterhouse - American Public Power Association - 4 - NA - Not Applicable	
Answer	
Document Name	
Comment	
APPA has multiple concerns with the proposed definition of distributed energy resources (DER) and adding this scope to the MOD-032 Standard, as outlined below. **Scope Expansion and non-NERC Registered Entities** The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or	

Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient to ensure the expansion of scope will be effective or reasonable.

The Technical Rationale states "the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases." The information includes "Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS," "Real power capability (minimum and maximum)," "Reactive power capability (minimum and maximum)," "Generator type (solar, battery, etc.)," and "In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control." While DPs may receive some or all of this information at the interconnection request stage, and can pass whatever data they have to their PC and TP, the draft standard must be revised to account for the fact that the DPs and TOs do not own or control these DERs, and thus cannot be held responsible for the completeness or accuracy of the data they themselves receive from the DER owners. For example, a DER owner might inadvertently change its nameplate capacity by replacing a damaged inverter with a different capacity from the original due to supply chain issues, and might not think to inform its DP of the change. More fundamentally, some solar installations, whether commercial, industrial, or homeowners installing on rooftops, do so without taking advantage of net metering or otherwise complying with their distribution utility's interconnection requirements—in other words, DPs may not have complete information about the *location* of DERs on their systems, let alone the capacity, type, and in-service date. Where customers *do* take advantage of net metering, the metering devices are generally not production meters, which highlights a concern regarding the SDT's proposal to revise the existing requirement for "aggregate demand" data to state that "For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources." Indeed, it is the nature of "net metering" that the data produced and collected is demand offset by DER output, not separate gross demand and generation values.

A registered entity cannot provide data that the registered entity itself does not have. In particular, it would be unrealistic to expect a TO or DP to have information about unregistered DERs at the same level of detail and accuracy that the unregistered DER owners can provide about their own facilities, nor would it be reasonable to hold a TO or DP responsible for gaps or inaccuracies in the data provided by an unregistered DER owner.

Accordingly, the SDT should, at minimum, revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy; and (b) the requirement to provide "aggregate demand" can be satisfied by net demand data, at least with respect to net-metered DERs.

Implementation Plan

APPA does not agree with the proposed implementation plan for the DER definition. This definition will eventually be used in several future NERC Standard revisions. Some of these revisions may have a shorter implementation timeframe than Project 2022-02. The effective date of the DER definition needs to be coordinated with the other planned Standard revisions to ensure the timing supports implementation of the other Standard revisions.

Coordination with Other Standard Changes

APPA is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 "NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper." The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences. For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

When reviewing the DER definition, entities need to understand how this definition will be used in all of the impacted Standards. APPA recommends creating a standalone Standards Project that addresses the DER definition development for all future Standard changes, similar to Standard Project 2016-02 and Standard Project 2015-09.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
BES expansion
Inclusion of DER as a BES facility is not being considered as part of this project.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale)

and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

DER definition
The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.

The RSTC approved a White Paper produced by SPIDERWG identifying standards that may require revision due to DER: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf
Other projects could propose to accelerate the DER definition timeline if necessary.

MOD-026 is currently only applicable to BES facilities. There would need to be a separate project to add DER applicability to MOD-026.

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1

Answer	
Document Name	2022-02_Unofficial Comment Form_SRC_07-14-23_Final (as filed).docx

Comment

To achieve this project's objective [1] in an effective and efficient manner, the SRC recommends NERC do the following:

1. **Retain the need to define Distributed Energy Resources (DERs) as part of the scope of this project (as opposed to initiating another project).** This would be beneficial because:

a. The SDT for this project already includes many SPIDERWG members. Therefore, the existing team already has the "right" representation and expertise to perform this task.

b. The existing SDT has discussed and examined a broad range of DER definitions, so a substantial portion of the work needed to develop a DER definition has already been done, thereby giving the existing SDT a leg up on this effort.

c. It would eliminate the need for NERC to initiate another project and for industry to provide representatives to staff another team that would be starting this work from scratch (i.e., a loss of efficiency) and which may not be able to attract a commensurate level of expertise, e.g., SPIDERWG members (i.e., a loss of effectiveness).

2. **Revise the DP registration criteria found in the Rules Of Procedure (ROP), Appendix 5B, Section III** and in the corresponding **ERO Enterprise Registration Practice Guide Distribution Provider "directly connected" Determinations.pdf (nerc.com)** to more closely align with the criteria proposed in its Work Plan to register Inverter-Based Resources (IBRs) under FERC Docket RD22-4-000.

When the DP criteria (RoP, Appendix 5b, Section III.a.1) in the **ERO Enterprise Registration Practice Guide Distribution Provider "directly connected" Determinations.pdf (nerc.com)** was updated in July 2018, two key aspects were modified that are now in direct opposition to the approach NERC is taking with respect to registering IBRs:

a. **The amount of peak load served by the DP system was increased from 25 MW to 75 MW.** This is in direct contrast to NERC's Work Plan for the registration of IBRs whereby NERC is seeking to decrease the registration threshold from 75 MVA to 20 MVA.

b. **The connection point for peak load was changed from "directly connected to the "Bulk Power System (BPS)" to "directly connected to the BES."** Again, this is in direct contrast to NERC's Work Plan for the registration of IBRs whereby NERC is seeking to register IBRs that are directly connected to the BPS.

As the penetration of Distributed Energy Resources (DERs) increases, there will be a reliability need to register a broader range of Distribution Providers as was acknowledged with IBRs. The SRC requests NERC address this issue as part of this project, perhaps as a separate phase.

3. Dual Planning Authority (PA) / Planning Coordinator (PC) Designation

While there is justification to reference both the Planning Authority and Planning Coordinator in the Applicability section (section 4) since NERC Appendix 5B: Statement of Compliance Registry Criteria, dated January 19, 2021, still uses both terms, the explanatory paragraph in Part 4.1.4 refers to synchronization between registration criteria and the NERC functional model, which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the SRC requests the explanatory paragraph be deleted from Part 4.1.4 as illustrated below and in the attached file:

4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

Planning Coordinator (PC) Interface

The SRC notes the importance of retaining the PC's flexibility with respect to determining the process used to acquire modeling data. While some PCs prefer to interface directly with the DP as noted in footnote 2 (*see* page 20 of 22 of the standard), other PCs prefer to interface with the Transmission Owner (TO) or Transmission Planner (TP). In the latter example, the TO or TP maintains the interface with the DP.

Footnote 2: *For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.*

The SRC requests the SDT clarify the required interfaces under the standard are "as directed by the PC" so information flows to the appropriate entities as part of the data collection process. Leave flexibility to the PC for determining how this data is collected as proposed below:

2. Aggregate Demand2 [DP3, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status*

Footnote 2: For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.

Footnote 3: Wherever DP is noted as the functional entity responsible for reporting data in the table, a Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.

Footnote 4: Including synchronous condensers and pumped storage.

Other Clarifications

1. Attachment 1, "steady state" column, item 9

a. Strike "feeder" to provide the TP/PC with flexibility in tracking the status of UVLS and UFLS (i.e. as aggregated values or as individual feeders).

b. Clarify the use of "and/or" with regards to UVLS and UFLS. Using "and/or" creates four possible combinations that must be tracked: UFLS only, UVLS only, Both UFLS and UVLS, and neither UFLS nor UVLS. Is the intent of the SDT to track all these possible permutations?

The SRC requests the SDT modify item 9 to add the following details:

9.a. Location (bus from item 1) and if DER is subject to UFLS and/or UVLS

b. Real power capability (gross minimum and maximum)

c. Reactive power capability (gross minimum and maximum)

2. **Attachment 1, footnote 4 -** clarify the use of "/" as illustrated below:

4 The TP or PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance.

[1] From pages 1-2 of the SAR: "*Update MOD-032-1 to: (1) include "data requirements and reporting procedures" for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.*"

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
A NERC Glossary definition for DER was proposed.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP.

Change made to address PC/PA applicability.

Data flow processes
Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale.

The intent of the SDT is to track all of the identified permutations of UFLS and UVLS.

Changes made to item 9 to address the concern and provide PC/TP flexibility.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

General comment: As stated in EEI's response to Question 1, we support the replacement of LSEs with DP, however, Attachment 1 goes beyond the replacement of LSEs with DP and includes TOs as an additional replacement where there are no registered DPs. This change should be stricken from the proposed draft of MOD-032-2. Registration problems cannot be solved through compliance obligations placed on registered entities who do not participate in the approval of DER interconnections or have any ability to compel the sharing of DER data contained on networks outside their purview.

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: Footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Facilities Section
The SDT determined that a Facilities section is not necessary. Modifications were made to clarify data obligation for TOs and DPs with respect to data related to DER, for which a definition is proposed.

Improper DP/TO applicability

The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP. Aggregate Demand The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale. Adjustments made to Attachment 1 – many identified items would be specified in PC/TP procedures. Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1.	
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	
Answer	
Document Name	
Comment	
SMUD and BANC support the comments submitted by APPA, especially with regards to the DER definition and Coordination with Other Standard Changes.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. See response to APPA.	
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	

Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project:

Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”.

Delete the 2nd paragraph in section 4.1.4

R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to their PC or TP. Suggesting either adding “written” to R3 or removing it from the R3 VSL.

R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…”

R2 Severe VSL: Missing the TO entity after the last “OR”.

R3 VSL: incorrect references to R4 instead of R3 in all VSL levels.

R3 Severe VSL: should read “or within a longer period of 45 days agreed upon by the notifying Planning Coordinator or Transmission Planner” instead of “or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner”

TO's and DP's cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER's are not obligated to provide the data.

In Attachment 1, under Dynamics, the following change should be made:

Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

In Attachment 1, under Steady-State, the following change should be made:

Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS

b. Real power capability (minimum and maximum)

c. Reactive power capability (minimum and maximum)

d. Generator type (solar, battery, etc.)

e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control, and/or frequency control.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Change made to address PC/PA applicability – please see Technical Rationale.

R3/R3 VSL – proposed change is beyond the SAR scope and more substantial than a typo/correction; no change made.

R1 Severe VSL – correction made to obvious typo.

R2 Severe VSL – correction made to obvious typo.

R3 VSL – correction made to obvious typo.

R3 Severe VSL – proposed change is beyond the SAR scope and more substantial than a typo/correction; no change made.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

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

SRP recommends adjusting the definition for the Distribution Provider before making the proposed adjustments so that there is clear delineation of roles and responsibilities.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
Modifying the definition of Distribution Provider is beyond the scope of this project.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource recommends the drafting team consider the category of “Transients” (specifically EMT Models) as an inclusion in required data submittals in Attachment 1 to reach the SDT’s goal to “address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments” per the MOD-032 SAR. While interconnection-wide models are built using dynamic and short circuit studies and not transient studies, there are still situations where border areas are studied between differing TPs or PCs, and the need for these EMT models to be available is necessary to better model aggregate levels of DERs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Establishing EMT modeling and data requirements for DER is beyond the scope of Project 2022-02.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
Attachment 1 Data Reporting table (Steady State Column items 2, and 9, and Dynamics Column items 5, and 10) has added language indicating that the Transmission Owner (TO) is the responsible entity for submitting modeling data when a demand is not associated with a registered Distribution Provider. AZPS requests clarification regarding the type of entity that would have load, but not be a registered	

distribution provider. AZPS is concerned that the Transmission Owner may not have the ability to produce or acquire certain load information from an unregistered entity unless there is some other type of contractual relationship in place.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.	
Imane Mrini - Austin Energy - 6	
Answer	
Document Name	
Comment	
Austin Energy supports APPA's comments. Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy"	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	
Austin Energy supports APPA's comments. Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	

DER Definition:

Southern Indiana Gas & Electric Co. (SIGE) believes the potential impact of the DER definition exceeds the current scope of Project 2022-02 and suggestions expanding the scope of the current project and/or initiating a separate NERC Reliability Standards project to address the DER definition.

Applicability:

SIGE believes there is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. Further clarity on the DER definition is needed.

Attachment 1:

SIGE agrees with EEI's comments that changes to MOD-032-2 should be put on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms intended to address Inverter Based Resources (IBRs) that impact the Bulk Power System (BPS) .

SIGE is supporting EEI's **Footnote 2**.

SIGE recommends replacing the '****' in **Footnote 4** with "**or**". "The TP/ or PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance."

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.
The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.

The RSTC approved a White Paper produced by SPIDERWG identifying standards that may require revision due to DER: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf
The project scope for Project 2022-02 explicitly includes consideration of a DER definition.

Modifications were made to clarify data obligation for TOs and DPs with respect to data related to DER, for which a definition is proposed.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP.

Adjustments made to Attachment 1, including footnote 4 – also, see response to EEI.

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	

Attachment 1 - Under Steady State (2, 9) Recommend changing language to [DP (when a Demand connected to the DP is not associated with a registered DP), TO (when a Demand connected to the TO is not associated with a registered DP)]. Under dynamics (5, 10) Recommend changing language to [DP (when a Demand connected to the DP is not associated with a registered DP), TO (when a Demand connected to the TO is not associated with a registered DP)]. An entity that has an unregistered DP connected to them will have both the knowledge that the entity exists and contacts for them to obtain the required information. If a TO is required to provide information for an unregistered DP that receives its service through a registered DP, they may not know the entity exists or have the required contacts to obtain the required information. As written, the SDT is setting the TO up to fail and be non-compliant.

Attachment 1 steady state, modify (9e) to DER capabilities related to ride-through, voltage control and/or frequency control, if available, or In-service date or other information to be used to make assumptions about them if this information is not available. Recommend trying to get the actual information if it is available rather than always making assumptions for this.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Added footnote 5 to address compliance concerns associated with collecting data from unregistered entities. Modified 9d (formerly 9e) to address concern about assumed capability. Modifications to footnote 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1.	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	
Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project: • Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”. • Delete the 2nd paragraph in section 4.1.4 R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to its PC or TP. Suggesting either adding “written” to R3 or removing it form the R3 VSL. R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…” R2 Severe VSL: Missing the TO entity after the last “OR”. R3 VSL: incorrect references to R4 instead of R3 in all VSL levels. R3 Severe VSL: should read “or within a longer period of 45 days agreed upon by the notifying Planning Coordinator or Transmission Planner” instead of “or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner” TO’s and DP’s cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER’s are not obligated to provide the data. In Attachment 1, under Dynamics, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP) In Attachment 1, under Steady-State, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP) a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS b. Real power capability (minimum and maximum) c. Reactive power capability (minimum and maximum) d. Generator type (solar, battery, etc.) e. In-service date or other information to be used to make assumptions about DER capabilities related to ride through, voltage control and/or frequency control.	
Likes 0	

Dislikes 0	

Response
Thank you for your comment. Change made to address PC/PA applicability – please see Technical Rationale. R3/R3 VSL – proposed change is beyond the SAR scope and more substantial than a typo/correction; no change made. R1 Severe VSL – correction made to obvious typo. R2 Severe VSL – correction made to obvious typo. R3 VSL – correction made to obvious typo. R3 Severe VSL – proposed change is beyond the SAR scope and more substantial than a typo/correction; no change made. Improper DP/TO applicability The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	

Comment
CEHE finds the proposed revisions to MOD-032-2, Attachment 1 too detailed and prescriptive. The NERC Standard should be written to give Planning Coordinators (PC), Transmission Planners (TP) and Transmission Service Providers (TSP) the flexibility to coordinate and determine

the specific data requirements that are needed for the planning models under MOD-032-2, Attachment 1. CEHE recommends that data reporting requirements listed in Attachment 1 be determined by the PC, in coordination with TP. In the ERCOT region, processes are already in place to define these data requirements through the coordination of the Planning Coordinator and Transmission Planners as part of various regional working groups. CEHE also supports the comments as submitted by the Edison Electric Institute (EEI) regarding the development of a DER definition separate from the NERC Reliability Standards Project 2020-02. CEHE agrees with EEI comments on how presently, Transmission Owners (TOs) and Distribution Providers (DPs) have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will yield little useful data. Subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represents untenable regulatory obligations they cannot fulfil. To address this concern, CEHE suggests that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operate, be removed. CEHE agrees with EEI comments relative to TOs. These entities may have no insights on DERs of unregistered DP systems and therefore should not be held accountable for supplying this type of information. CEHE supports the additional comments submitted by EEI regarding footnote 4 of the SAR.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

Data flow processes Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale. Also, see response to EEI.
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 (EEI) for queston #2.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. See response to EEI.
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	
Document Name	

Comment
Southern Company supports comments submitted by EEI on potential implementation challenges.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

WEC Energy Group appreciates the opportunity to provide comment and suggests for consideration the inclusion of a specific MW threshold below which DER modeling is not required.

WEC Energy Group is also in support of the comments submitted by EEI which state:

"EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: Footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed."

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The SDT determined that a Facilities section is not necessary. Modifications were made to clarify data obligation for TOs and DPs with respect to data related to DER, for which a definition is proposed.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP.

Aggregate Demand
The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale.

Adjustments made to Attachment 1 – many identified items would be specified in PC/TP procedures. Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	
Comment	
The NAGF has no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lindsey Mannion - ReliabilityFirst – 10	
Answer	
Document Name	
Comment	
RF notes the draft standard revision also adds DER data under the steady state and dynamics columns in Attachment 1: Data Reporting Requirements, addressing industry need (1) from the SPIDERWG MOD-032 SAR and appreciates the efforts of the SDT on this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	
Document Name	

Comment
RE: Definition of Distributed Energy Resource (DER): Please consider that the definition of Distributed Energy Resource (DER) should be more generic, such as, "Real Power and Reactive Power resources connected on the distribution system, in non-isolated parallel operation. Please consider changing active power to Real Power since "active power" is not included in the NERC Glossary of Terms and is in literature a synonym to Real Power and should not be defined differently. In the NERC Glossary of Terms, Real Power is defined as, "The portion of electricity that supplies energy to load." In the slides presented at the Project 2022-02 webinar (June 27), "Active power" was proposed to "indicate[s] that the scope is focused on only those facilities that may be exporting real power to the power system or offsetting real power load (e.g. residential or commercial rooftop solar, even if they only operate at unity power factor or don't have any reactive power capability). This would exclude examples such as charging-only electric vehicle (EV) installations and controllable load options." This proposal seems to indicate active power no longer being used as a synonym to Real Power, which could cause a potential risk of misinterpretations. RE: Applicability – Functional Entities, Section 4.1.4: Please consider removing the "Planning Authority" function from section 4.1.4 since Planning Coordinator is the preferred function name. Please consider that Project 2017-07 Standards Alignment with Registration was previously removing "Planning Authority" from other standards such as MOD-031-2 and MOD-033-1, in-advance of the removal of "Planning Authority" from Rules of Procedure - Appendix 5B: Statement of Compliance Registry Criteria. RE: Section C. Compliance: Please consider adding (CEA) as the abbreviation of "Compliance Enforcement Authority" to section 1.1. Please consider using the abbreviation CEA in section 1.2. RE: Attachment 1: Data Reporting Requirements: Please consider limiting steady-state data for new item 9 to read as, "9. Distributed Energy Resource (DER) data4 [DP]" Please consider that sub-parts a., b., c., d., and e. are not necessary since DER data requirements can be agreed upon per requirement R1.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Active power was replaced with Real Power in the proposed DER definition. DER definition

The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale. Use of CEA abbreviation was not a significant topic for industry comment – no change made. Adjustments made to Attachment 1. The SDT believes that the intent of the SAR was to establish some minimum level of DER data needed.

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy supports the comments of the EEI and the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to EEI and the MRO NSRF.	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
We appreciate the SDT's inclusion of a draft definition for a "Distributed Energy Resource (DER)" in Draft 1 of MOD-032-2. We suggest the words 'Generators and energy storage technologies…' in the definition be replaced with 'Sources of Electrical Energy…'. The NERC Glossary of Terms defines "Electrical Energy" as "The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh)" and is technology neutral. While a DER definition is important, the definition in	

combination with adding DP applicability may not provide the clarity for applicability that the SDT concludes in the Technical Rationale. The SDT should consider whether utilizing a new Facilities applicability section (4.2) could provide further scope clarity.

We believe section 4.1.4 should be updated to simply "Planning Coordinator". This would be consistent with the direction taken in other NERC standards that previously contained similar language regarding PA/PC applicability (see changes made to MOD-031-3 and MOD-033-2 under Project 2017-07, Standards Alignment with Registration). The Project 2017-07 webpage contains the following statement about MOD-032-1:

"MOD-032-1 will not be revised at this time, but may come back into Project 2017-07. The work of the System Planning Impact from Distributed Energy Resource Working Group (SPIDERWG) is ongoing at the time of the final posting for Project 2017-07. In June 2018, the NERC Planning Committee (PC) formed the SPDERWG subcommittee to address Distributed Energy Resource (DER) impacts on the bulk power system (BPS). Currently, the subcommittee has proposed a Standard Authorization Request (SAR) for MOD-032-1 pertaining to DERs. The SAR has recently been reviewed by the PC. At this time, the Project 2017-07 drafting team will not take any action in reference to the MOD-032 standard until the SPIDERWG has completed their initial efforts."

While the Draft 1 Technical Rationale notes that the currently posted "Appendix 5B: Statement of Compliance Registry Criteria" still uses the Planning Authority term, a cursory review of all currently active standards reflects that a transition to "Planning Coordinator" in the applicability sections is almost complete, so making this change in MOD-032-2 would complement this transition. FAC-014-3, effective 4/1/2024, will incorporate the PA to PC change for that standard.

We noted in our comments on the SAR that a Distribution Provider may not always be the most practical source for the DER modeling data needed by the PC and TP. We recognize that the SDT has allowed for the flexibility of a Transmission Owner to also be a source for DER modeling data in Draft 1. However if the DP or TO is not directly affiliated with the DER owner, would their need to collect the DER model data from the entities that possess it not essentially mirror the PC and TP's need under R1? The DP and TO might need their own requirement(s) to develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures to obtain DER modeling data (potentially from unregistered entities that don't have an obligation to comply with NERC's Reliability Standards) that would subsequently be passed on to the PC and TP. A "DER data entity" could also be added to the applicability section (reference PRC-006-5 for precedent) with a broader range of registered entity options to fulfil that role (e.g., DP, UFLS-Only DP, TO, RP, GO).

We interpret the implementation plan to mean that the PC and each of their TPs will have 24 months to jointly update their modeling data requirements and reporting procedures to incorporate the changes in Attachment 1. The entities responsible for providing DER modeling data to the PC/TP will then have 12 months to comply. We believe the initial collection and submittal of DER data will be equally if not more

time consuming than the PC/TPs efforts to update their modeling data requirements and reporting procedures. As noted above, after receiving the PC/TP's updated modeling data requirements and reporting procedures, the DER data collectors may need to perform outreach and communicate their own procedure/schedule for receiving the data from others. We suggest the implementation plan be revised to allow 24 months (rather than 12 months) after the effective date for the initial performance of R2, R3 and R4.

We suggest that further development of MOD-032-2 and its associated implementation plan be paused until it can be performed in closer conjunction with NERC's three year plan to register 'GO-IBRs', which is just beginning; and the "Modifications to FAC-001 and FAC-002" Standard Authorization Requests approved for posting at the NERC Standards Committee's May 17, 2023 meeting (no NERC project number assigned yet). Addressing these items (and perhaps other IBR related standards initiatives) in a piecemeal fashion will lead to less optimal results and confusion in the industry.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The proposed DER definition refers specifically to generators and storage technologies which would exclude transient sources of active power. Clarification added to Technical Rationale.

Facilities Section
The SDT determined that a Facilities section is not necessary. Modifications were made to clarify data obligation for TOs and DPs with respect to data related to DER, for which a definition is proposed.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP. Implementation Plan The expectation is that TOs and DPs would participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of R1. Thus, TOs and DPs should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of R2, R3, and R4. GO-IBR registration would not cover many DER installations. The SDT views the GO-IBR registration as a separate effort that should not impact moving forward with MOD-032-2 as proposed.
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	
PPL NERC Registered Affiliates do not agree with the separate inclusion of DER data in Attachment 1. A lack of specific reference to DER data does not mean that the data does not exist or is not already attainable by PCs and TPs under the existing standard. There are already specific provisions in the Standard allowing for the collection of such data. We do not believe there are gaps or lack of clarity within the currently approved MOD-032-1. Directing how an entity should collect and model such data is overly prescriptive, will increase administrative burden, and limit innovation in modeling DERs. The industry is just now learning how DERs are going to affect the BES. It is counterproductive to circumscribe how entities should meet their compliance requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1.	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kinte Whitehead - Exelon – 3	
Answer	
Document Name	
Comment	
Exelon concurs with the concerns expressed in the EEI comments. Requirements for DPs and TOs to provide Aggregate Demand and DER data should be limited to the aggregate data currently available to the entity. For Attachment 1, Steady-State 9e, we suggest removing the implied requirement for the “in-service dates”. Consider restating Attachment 1, Steady-State 9e as, “Information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.” The Technical Rationale document can be modified to discuss how in-service dates may support the response to Attachment 1, Steady-State 9e.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. See response to EEI. Improper DP/TO applicability The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. Made adjustment to Attachment 1 to remove “service date”.	
Daniel Gacek - Exelon – 1	
Answer	
Document Name	
Comment	
Exelon concurs with the concerns expressed in the EEI comments. Requirements for DPs and TOs to provide Aggregate Demand and DER data should be limited to the aggregate data currently available to the entity. For Attachment 1, Steady-State 9e, we suggest removing the implied requirement for the “in-service dates”. Consider restating Attachment 1, Steady-State 9e as, “Information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.” The Technical Rationale document can be modified to discuss how in-service dates may support the response to Attachment 1, Steady-State 9e.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. See response to EEI. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. Made adjustment to Attachment 1 to remove “service date”.	
Brittany Millard - Lincoln Electric System – 5	
Answer	
Document Name	
Comment	
LES does not agree with the SDT proposed definition of DERs. The definition should be more in line with the FERC Energy Primer definition, already in place.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	

Document Name	
Comment	
The DP must be able to bound restrictions/limitations to TP request due to limited data availability, reasonableness, etc., when DER data requirements are made. Also, when determining the size of each DER, a minimum size of 500 kVA should be required for inclusion. Anything less than 500kVA would require an onerous amount of effort to provide accurate data, which would result in data being outdated and/or obsolete, etc. There is limited data available (MOD-032-2 Attachment 1) for DP area small DER generation (e.g., residential solar, small commercial), therefore the accuracy of aggregated small DER generation for BES system impact modeling is limited.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. DER MW thresholds NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02.	
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	
Thank you for your support.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to MRO NERC Standards Review Forum (NSRF).	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	

Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to NPCC/RSC.	
Nicolas Turcotte - Hydro-Quebec (HQ) – 1	
Answer	
Document Name	
Comment	

1) Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project:

- Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”.
- Delete the 2nd paragraph in section 4.1.4

2) R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to its PC or TP. Suggesting either adding “written” to R3 or removing it form the R3 VSL.

3) R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…”

4) R2 Severe VSL: Missing the TO entity after the last “OR”.

5) R3 VSL: incorrect references to R4 instead of R3 (more specifically R3.2) in all VSL levels.

6) R3 Severe VSL: should read "[...Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response after 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner)" instead of "Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner)."

7)TO's and DP's cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER's are not obligated to provide the data.

8) In Attachment 1, under Dynamics, the following change should be made:

- Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)
- In Attachment 1, under Steady-State, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS

b. Real power capability (minimum and maximum)

c. Reactive power capability (minimum and maximum)

d. Generator type (solar, battery, etc.)

e. In-service date or other information to be used to make assumptions about DER capabilities related to ride through, voltage control and/or frequency control.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Change made to address PC/PA applicability – please see Technical Rationale.

R3/R3 VSL – proposed change is beyond the SAR scope and more substantial than a typo/correction; no change made.

R1 Severe VSL – correction made to obvious typo.

R2 Severe VSL – correction made to obvious typo.

R3 VSL – correction made to obvious typo.

R3 Severe VSL – proposed change is beyond the SAR scope and more substantial than a typo/correction; no change made.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E provides the following:

The MRO New Standard Review Forum (NSRF) has provided additional comments that PG&E wishes to support related to the DER definition. PGAE supports the recommendation that the definition should be removed from this modification and addressed in a separate project since it would impact many Standards currently being worked on or planned for in the future. With seven (7) different DER definitions

currently being provided from such sources as the NERC SPIDERWG, NARUC, IEEE, and the California PUC, the Project 2022-02 effort will cause further confusion for the industry. For this reason, PG&E will be voting Negative for this proposed modification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.	
Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,7 - SERC	
Answer	
Document Name	2022-02_Unofficial Comment Form_May2023.docx
Comment	
1. Will there be an aggregate DER threshold (either nameplate or net injection to the grid) above which the DP should submit modeling data to the TP and PC for inclusion in transmission planning models? MOD-025, MOD-026, and MOD-027 standards are being revised to limit applicability to resources included in either I2 or I4 of the BES definition (individual units > 20 MVA or an aggregate plant > 75 MVA). Should thresholds for MOD-032 DER modeling be consistent with the other NERC modeling standard applicability thresholds? 2. Will the NERC BES Reference document be revised to include DER generation (individual units and/or DER aggregations)? 3. Are these DER data reporting requirements limited to merchant DER installations in the future only? ○ It will be challenging to obtain steady-state and dynamic data for each individual installation that has taken place over the years in the past, especially for non-merchant applications (such as residential roof-top solar resources). Hoe are DPs expected to obtain this data and who will bear the cost associated with this process?	

○ How will DPs be able to obtain and verify the in-service dates of each individual distribution connected resource that has occurred in the past? ○ Most of the residential and other non-merchant solar and battery installations fall below the installed capacity threshold at which such resources are required to go through the distribution interconnection detailed study process. How are DPs expected to collect steady-state and dynamic data on such resources, even if occurring in the future?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. Inclusion of DER as a BES facility is not being considered as part of this project. Data for all DER that satisfy the proposed DER definition should be reported, subject to the joint PC/TP modeling data requirements and reporting procedures developed per R1. Improper DP/TO applicability The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.	
Kimberly Turco - Constellation - 6	
Answer	

Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behald of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	
Document Name	
Comment	
General comments on MOD-032-2: a. In Section 4. Applicability, under 4.1.4, BC Hydro recommends that the wording “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)”, be changed to “Planning Coordinator”. Retaining the current wording may create confusion or result in misinterpretation, especially for those utilities that treat PA standards and PC standards differently. A PC-only approach has been used in other recently approved NERC standards and those that are being developed, such as FAC-002-4, MOD-033-2, and MOD-026-2. b. BC Hydro recommends that in Attachment 1, the language used in the DER steady-state data section (Item 9) be generalized to account for distribution-connected hydroelectric generators. A suggested wording is provided below for consideration:	

"…c. Reactive power capability (minimum and maximum) *d. Fuel type (solar, wind, hydraulic, battery, etc.)* *e. Generator type (synchronous, inverter-based resource, etc.)* *f. In-service date or other …"*

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Change made to address PC/PA applicability – please see Technical Rationale. The SDT intent is to maintain PC/TP flexibility for consistently collecting accurate data, but not be overly prescriptive on data collection processes with respect to developing modeling data requirements and reporting procedures per R1.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	

Comment
WECC believes there is value in including these Distributed Sources in system modeling, but is concerned that the proposed defintion may not satisfy that need. The definition of DER does not seem adequate. First, it includes non BES generation type resources that are beyond BES dispersed generation identified under inclusion I4 of the BES Definition. And thus, appears to go beyond the scope of mandatory standards applicability. A second issue is that because the definition has the qualifier "…connected to the Distribution Provider's system…" it would leave out any "DER" that did not have a registered Distribution Provider including any connected via some pathway directly to a Transmission System.

WECC believes that a focused effort on defining DER and addressing it within the BES Definition or in the NERC Glossary to be used consistently in all standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. A clarification was added to the DER definition indicating that the Distribution Provider reflects the NERC glossary of terms definition rather than the NERC registered entity.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
Per the Federal Power Act, NERC's jurisdiction is to establish and enforce Reliability Standards for the Bulk Power System. A NERC document, Understanding the Grid, published in March 2023, indicates that the generation and transmission components and their associated control systems make up the BPS, so requiring DP's to provide DER data that is connected to the Distribution system is outside of NERC's jurisdiction, unless the DER is connected to the transmission system such as non-BES generation. Furthermore, the NERC Glossary of Terms definition for Bulk Power System explicitly states that is does not include facilities used in the local distribution of electric energy, which aligns to the definition for bulk-power system in the Federal Power Act Section 215(a), definitions. DER on a DP's network is not that clear in the Technical Reference document. Please provide some examples similar to the BES reference document of what would not be in-scope DER and what would be in-scope DER on a DP's network. What happens if we are unable to obtain modeling data from OEMs for older DER inverters?	

What if we do not have the information to determine the collector system impedance values? What happens if residential, retail or commercial owners do not want to support this effort? What happens if an IBR OEM has gone out of business?	
Likes 1	Mearns James On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5;
Dislikes 0	
Response	
Thank you for your comment. Data for all DER that satisfy the proposed DER definition should be reported, subject to the joint PC/TP modeling data requirements and reporting procedures developed per R1. Based on the work of the NERC SPIDERWG and observed events around the world, it should be clear that DER can impact BPS reliability. Improper DP/TO applicability The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA believes that this definition would require adjustment of the BES inclusions and exclusions lists. For example, currently resources below 75 MVA are not required to submit the data that will be required of DER. This will result in entities not providing data for anything less than 75 MVA and citing exclusion (or lack of inclusion), even though the intent appears to require data submission from much smaller	

resources. BPA suggests excluding legacy equipment such as hydro, or perhaps the definition should only apply to inverter based resources (IBR.) It is also important to note that small generator owners are likely not financially able to test equipment (per MOD-025/026/027) in order to provide modeling data. This could result in shutting down such generators and associated loads costing local jobs in affected areas. BPA requests clarification and consistency regarding the use of Bulk Power System and Bulk Electric System. Both terms are being used.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Inclusion of DER as a BES facility is not being considered as part of this project. Data for all DER that satisfy the proposed DER definition should be reported, subject to the joint PC/TP modeling data requirements and reporting procedures developed per R1.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	

Comment
FE supports EEI's comments which state: EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

General comment: As stated in EEI's response to Question 1, we support the replacement of LSEs with DP, however, Attachment 1 goes beyond the replacement of LSEs with DP and includes TOs as an additional replacement where there are no registered DPs. This change should be stricken from the proposed draft of MOD-032-2. Registration problems cannot be solved through compliance obligations placed on registered entities who do not participate in the approval of DER interconnections or have any ability to compel the sharing of DER data contained on networks outside their purview.

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be removed. For these reasons, changes to MOD-032-2 should be placed on

hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
The SDT determined that a Facilities section is not necessary. Modifications were made to clarify data obligation for TOs and DPs with respect to data related to DER, for which a definition is proposed.

The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability.

However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information. See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale. Adjustments made to Attachment 1 – many identified items would be specified in PC/TP procedures. Modifications to footnotes 2 and 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1.	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	
Document Name	
Comment	
Comments to be supplied separately by AECC's Ayslynn McAvoy.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to AECC.	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	
Document Name	
Comment	

Project 2022-02 is more than the replacement of these registration identifiers as it also includes DER modeling data additions. The question above does not fully encompass the changes proposed for MOD-032-02. However, the changes for adding DER modeling data does seem appropriate and reflects the NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
· Can 4.1.4 be simplified to just Planning Coordinator? · Note 10 under dynamics in Attachment-1 assumes a specific model for each DER will be provided. Note 9 under steady state (and footnote 4) assume that DER could be aggregated. The dynamics model may also need to be aggregated and there should be a footnote regarding coordination of model parameters. The Resource Planner may need to be involved in the coordination for dynamic models in Years 1-10. · Regarding the DER definition provided under the section “New or Modified Terms Used in NERC Reliability Standards ”, did the SDT consider the definition provided in IEEE Std 1547-2018, especially Note-1(exclusion of Controllable loads used for demand response) and Note-2 (supplemental DER devices)?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Change made to address PC/PA applicability – please see Technical Rationale. Modifications to footnote 4 are intended to emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. DER definition The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports comments sumbtted by Tacoma Power.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to Tacoma Power.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
No Additional Comments	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	
Comment	

Tacoma Power has multiple concerns with the proposed DER definition and adding this scope to the MOD-032 Standard, as outlined in the next few bullets.

Scope Expansion and non-NERC Registered Entities

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient on their own to ensure the expansion of scope will be effective.

The Technical Rationale states “the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases.” However, there are large distribution utilities that are not registered as DPs, but have aggregate DERs that should be accounted for under the proposed MOD-032 Attachment 1 scope. To ensure the appropriate entities are held responsible, either the (1) BES definition needs to change to include DERs, (2) a new “DP-DER” registration needs to be created, or (3) the DP registration criteria needs to change to ensure the appropriate entities are held responsible. Of these three options, Tacoma Power recommends revising the DP criteria in ROP Appendix 5B, Section III, to include a new criterion to ensure distribution utilities that must provide data to support MOD-032, Attachment 1, are subject to NERC jurisdiction. This

approach aligns with the regulatory precedent set for UVLS programs, RAS schemes, and Protection System components under PRC-005 and PRC-006. Without a seperate effort to revise the DP registration, Tacoma Power cannot approve the draft MOD-032. The draft Standard cannot be fulfilled without these entities being held responsible for the data.

Below is an example mark-up of ROP Appendix 5B, Section III for NERC to consider in the ROP revision:

III.a.1 Distribution Provider system serving >75 MW of peak Load that is directly connected to the BES; or

III.a.2 Distribution Provider is the responsible entity that owns, controls, or operates Facilities that are part of any of the following Protection Systems or programs designed, installed, and operated for the protection of the BES:

- *a required Undervoltage Load Shedding (UVLS) program and/or*
- *a required Special Protection System or Remedial Action Scheme and/or*
- *a required transmission Protection System; or*

III.a.3 Distribution Provider that is responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs) pursuant to an executed agreement; or

III.a.4 Distribution Provider with field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks; or

III.a.5 Distribution Provider is the responsible entity that serves, controls, owns, or operates Distributed Energy Resources (DERs) exceeding 0.01 MW.

DER Definition

Tacoma Power supports the essence of the DER definition, but is concerned that it is unclear whether the proposed definition includes devices that have transient export of real power such as closed transition transfer switches, regenerative elevators/cranes, and industrial motors with regenerative braking. The proposed definition should be clarified to exclude these devices, while still including devices installed for energy storage such as batteries, flywheels, and Synchronous condensers. Tacoma Power suggests adding "for at least 30 seconds" to the definition so that the definition reads "... *providing active power for at least 30 seconds in non-isolated parallel operation*... "

The IEEE definition of DER includes both the energy resource plus any necessary supplemental equipment. Tacoma Power would like to see similar guidance within the NERC DER definition. This ensures that reactive power control devices such as capacitor and STATCOMS are correctly included in the DER model submittals.

Implementation Plan

Tacoma Power does not agree with the proposed implementation plan for the DER definition. This definition will eventually be used in several future NERC Standard revisions. Some of these revisions may have a shorter implementation timeframe than Project 2022-02. The effective date of the DER definition needs to be coordinated with the other planned Standard revisions to ensure the timing supports implementation of these other Standard revisions.

Coordination with Other Standard Changes

Tacoma Power is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 "NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper." The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences. For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

When reviewing the DER definition in this posting, entities need to understand how this definition will be used in other future Standard changes. Tacoma Power recommends one of the two following options to ensure impacts to other future Standard changes are considered in the definition development:

1. Provide a list of other Standards that will be impacted by this definition change in the "New or Modified Term(s) Used in NERC Reliability Standards" section of the MOD-032 redline, similar to the approach taken by Project 2019-04, Modifications to PRC-005, or
2. Create a standalone Standards Project that addresses the DER definition development for all future Standard changes.

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	

Response

Thank you for your comment.

Inclusion of DER as a BES facility is not being considered as part of this project.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP.

DER Definition
The proposed DER definition refers specifically to generators and storage technologies which would exclude transient source of active power. Clarification added to Technical Rationale.
The SDT feels that the DER definition is broad enough to include supplemental equipment, and in conjunction with item 9d in Attachment 1, adequately covers the concern. Clarification added to the Technical Rationale.
The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.

The RSTC approved a White Paper produced by SPIDERWG identifying standards that may require revision due to DER: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	
Document Name	
Comment	

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See response to MRO NSRF.	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	
Document Name	
Comment	
SMEs responded "MOD-032-1 provides language for the Planning Coordinators (PC) and their Transmission Planner(s) (TP) to request any, and all, modeling data pertaining to the development of steady-state, short circuit, and dynamics models. The language in MOD-032-1 currently allows the PCs and TPs to request DER data from TOs, GOs, and LSEs (Distribution Providers). Therefore, any language specific to the addition of DERs to MOD-032-1 would be redundant."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that this comment was answered when the Standards Committee approved the MOD-032 SAR.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
EEI Draft Comments should be included or referenced:	

{C}· {C}To better clarify the extent of DER resources that must be reported under MOD-032, EEI suggests that a Facilities section be added to this Reliability Standard.

{C}· {C}Footnote 2 – EEI asks that the SDT provide additional clarity regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While we understand why this would be desirable, most small DERs are not metered except for billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. We are further concerned that the manhours required to account for these DER offsets could be substantial adding excessive costs while providing questionable value to this change. As an alternative, EEI suggests that DPs and TOs could provide estimated DER offset values, which would require fewer manhours to develop and should provide sufficient value to the planning models.

{C}· {C}Steady-state and Dynamic columns

EEI is concerned that the data requests identified in Item 9 (Steady-state), and Item 10 (Dynamic) seek non-aggregated data, while the SAR specifies that aggregated DER data is to be supplied. To address this concern, we ask that both Items 9 and 10 be edited to make it clear that data requests to DPs and TOs are to be limited to aggregate DER data.

Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states “TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary”. This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The SDT determined that a Facilities section is not necessary. Modifications were made to clarify data obligation for TOs and DPs with respect to data related to DER, for which a definition is proposed.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

Data flow processes
Modifications to footnotes 2 and 4 are intended to address the concern and emphasize PC/TP flexibility in developing modeling data requirements and reporting procedures per R1. The intent of Attachment 1 is to specify the minimum required data but not procedures and methods. Clarification made in the Technical Rationale.

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	2022-02 Tables.PNG

Comment

- The NSRF recommends the SDT remove the DER definition from the proposed MOD-032-2 standard.

- The NSRF recommends NERC create a standalone Standards Project that addresses the DER definition development for all future Standard changes. As part of this project, the NSRF recommends revising the DP criteria in the Rules Of Procedure (ROP), Appendix 5B, Section III.

- NERC needs a way to register a DER or "DER aggregator" type entity, to ensure the appropriate entities are held responsible for NERC Reliability Standards.

Further:

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient to ensure the expansion of scope will be effective.

Currently there are seven definitions for DER. The SDT chose to create a new definition of DER separate from those.

The proposed definition:

Term(s): Distributed Energy Resource (DER) Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing active power in non-isolated parallel operation with the Bulk Electric System.

The SPIDERWG Terms and definitions document has six definitions for DER. The draft MOD-032-2 definition is different than the definitions contained in the document. See Table D.1: Alternate Definitions for DER-Related Concepts.

Link to SPIDERWG Terms and definitions document

Link to DER reference document – contains DER definition.

Distributed Energy Resources Connection Modeling and Reliability Considerations February 2017

The NERC Distributed Energy Task Force (ERTF) DER definition:

“Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Elec tric System (BES).”

The NSRF is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 “NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper.” The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences.

For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

The Technical Rationale states “the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases.” However, there are large distribution utilities that are not registered as DPs, but have aggregate DERs that should be accounted for under the proposed MOD-032 Attachment 1 scope. To ensure the appropriate entities are held responsible, either the:

1. BES definition needs to change to include DERs,

2. a new “DP-DER” registration needs to be created, or

3. the DP registration criteria needs to change to ensure the appropriate entities are held responsible.

From the SPIDERWG Terms and Definitions Working Document: -See Attachment	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Thank you for your comment.
New DER registration
The SDT views comments suggesting NERC registration of individual DER owners as unnecessary and impractical (similar to the impracticality of registering the load at every single house connected to the system) that would still require DPs and TOs to report what is connected to their systems unless NERC registration of every single rooftop solar installation is being proposed.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP.

Inclusion of DER as a BES facility is not being considered as part of this project.

DER definition
The SDT did review available definitions of DER and found existing definitions were not adequate to cover BPS reliability concerns. The proposed definition is aligned with the SPIDERWG working definition for DER. Additional details were added to the Technical Rationale.

Demand response was specifically excluded by SPIDERWG, so the cited example would impact intent related to other SPIDERWG recommendations and SARs.	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
NIPSCO agrees with the comments of the Edison Electric Institute (EEI) regarding the proposed TPL-001-5 Footnote 13d revision.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The first phase of Project 2022-02 is only proposing modifications to MOD-032.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP appreciates the efforts of the standards drafting team and sees the value of the proposed revisions to Attachment One. Even so, AEP would be unable to vote affirmative on this revised standard unless and until every entity providing DER data is a registered Functional Entity who is formally obligated to provide it. As is the case in existing standards where Generator Owners are obligated to provide similar data, entities who possess the needed DER data noted in the Attachment One revisions should likewise be registered and explicitly obligated to provide this data as well. While we are unsure if the existing Functional Entities classes are themselves sufficient, or if instead, a new class of Functional Entities might need to be considered and developed, the need nonetheless exists. NERC may wish to also consider the potential that such obligations could potentially cross Federal and State jurisdictional lines of responsibility, further illustrating the complexity-of and challenges-in developing obligations to obtain the DER data in the revised Attachment One.	

In addition, while the SDT has not provided a question regarding the proposed Implementation Plan, AEP believes additional time will be needed to accommodate the work pertaining to assets newly brought into scope. Rather than being required to comply with the obligations 12 months after the definition has become effective, we instead suggest it be 24 months after the definition has become effective.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
New DER registration
The SDT views comments suggesting NERC registration of individual DER owners as unnecessary and impractical (similar to the impracticality of registering the load at every single house connected to the system) that would still require DPs and TOs to report what is connected to their systems unless NERC registration of every single rooftop solar installation is being proposed.

Improper DP/TO applicability
The SDT contends that TOs and DPs (registered or not) have a reliability interest in knowing what is (and projected to be) connected to their systems with respect to the DER data items proposed to be added in Attachment 1. MOD-032-2 may help TOs get a better knowledge of what is being connected to their systems (and this may require amended interconnection agreements, as acknowledged in the Technical Rationale) and will require better coordination between TOs and DPs (registered or not) which should improve situational awareness and BPS reliability. However, the SDT recognizes the compliance challenges with obligating TOs and DPs to collect data from unregistered entities and added footnote 5 to Attachment 1 that requires TOs and DPs to pass through available information.

See Applicability section of Technical Rationale for SDT conclusion regarding modification of NERC registration criteria in ROP.

Implementation Plan
The expectation is that TOs and DPs would participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of R1. Thus, TOs and DPs should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of R2, R3, and R4.

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer

Answer	
Document Name	
Comment	
The Project 2022-02 SDT should review and coordinate with ERO efforts separately filed with FERC in the NERC proposed work plan to register GO-IBRs. Recognizing the current and expected state of DER and inverter-based resources in North America demands that any revisions proposed to the MOD-032-2 Reliability Standard respect functional registrations and corresponding cognizance of modeling data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. GO-IBR registration would not cover many DER installations. The SDT views the GO-IBR registration as a separate effort that should not impact moving forward with MOD-032-2 as proposed.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder
Standards Announcement
Project 2022-02 Modifications to TPL-001 and MOD-032

Initial Ballots and Non-binding Polls Open through July 14, 2023

Now Available

Initial ballots and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern Friday, July 14, 2023** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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 2022-02 Modifications to TPL-001 and MOD-032 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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Modifications to TPL-001 and MOD-032

Formal Comment Period Open through July 14, 2023
Ballot Pools Forming through June 29, 2023

Now Available

A 45-day formal comment period for **Project 2022-02 Modifications to TPL-001 and MOD-032** is open through **8 p.m. Eastern, Friday, July 14, 2023** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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, Thursday, June 29, 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 **July 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 2022-02 Modifications to TPL-001 and MOD-032 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: 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 IN 1 ST
Voting Start Date: 7/5/2023 12:01:00 AM
Voting End Date: 7/14/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 291
Quorum: 84.54
Quorum Established Date: 7/14/2023 1:37:12 PM
Weighted Segment Value: 41.82

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	79	1	19	0.317	41	0.683	0	5	14
Segment: 2	7	0.7	5	0.5	2	0.2	0	0	0
Segment: 3	64	1	14	0.275	37	0.725	0	1	12
Segment: 4	15	1	3	0.3	7	0.7	0	2	3
Segment: 5	74	1	26	0.441	33	0.559	0	4	11
Segment: 6	44	1	13	0.361	23	0.639	0	3	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	4	0.4	1	0.1	0	2	0
Totals:	291	6.2	84	2.593	144	3.607	0	18	45

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Lori Frisk		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	Comments Submitted
1	Western Area Power Administration	Sean Erickson		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A

5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett	Megan Caulson	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A

5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Shawna Satterwhite	Negative	Third-Party Comments
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Negative	Third-Party Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A

1	Dairyland Power Cooperative	Karrie Schuldt	Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost	Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt	Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber	Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff	Negative	Third-Party Comments
3	Salt River Project	Mathew Weber	Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard	Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson	Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen	Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer	Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons	Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder	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
1	Long Island Power Authority	Isidoro Behar	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp	Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson	Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos	Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson	Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith	Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour	None	N/A

6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party

					Comments
6	Duke Energy	John Sturgeon		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Salt River Project	Sarah Blankenship		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
6	AEP	Justin Kuehne		Negative	Comments Submitted
3	AEP	Kent Feliks		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A

5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		None	N/A
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Emma Halilovic		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Brandon Smith		Negative	Comments

				Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Negative	Comments Submitted
10	Midwest Reliability Organization	William Steiner	Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman	Negative	Comments Submitted
1	JEA	Joseph McClung	Negative	Third-Party Comments
3	APS - Arizona Public Service Co.	Jessica Lopez	None	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor	Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo	Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker	Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons	Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger	Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman	Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Daniel Herring	Affirmative	N/A
6	New York Power Authority	Shelly Dineen	Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry	Affirmative	N/A
1	Great River Energy	Gordon Pietsch	Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu	Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender	Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Melanie Wong	Negative	Comments Submitted
5	Manitoba Hydro	Kristy-Lee Young	Negative	Comments Submitted
				Third-

10	New York State Reliability Council	Wesley Yeomans		Negative	Party Comments
5	BC Hydro and Power Authority	Quincy Wang		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Negative	Third-Party Comments
1	Entergy	Brian Lindsey	Kristen Long	Affirmative	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Negative	Comments Submitted
4	Electricities of North Carolina	Marcus Freeman		Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
3	Entergy	James Keele		Affirmative	N/A
5	Salt River Project	Thomas Johnson		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		Abstain	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A

5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	JEA	John Babik		Negative	Third-Party Comments
1	Lower Colorado River Authority	Matt Lewis		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A

3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
1	M and A Electric Power Cooperative	William Price		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A

3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	None	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
3	JEA	Marilyn Williams	Negative	Third-Party Comments
6	Western Area Power Administration	Chrystal Dean	Negative	Third-Party Comments
6	Xcel Energy, Inc.	Steve Szablya	Negative	Third-Party Comments
5	LS Power Development, LLC	C. A. Campbell	None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan IN 1 OT
Voting Start Date: 7/5/2023 12:01:00 AM
Voting End Date: 7/14/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 239
Total Ballot Pool: 289
Quorum: 82.7
Quorum Established Date: 7/14/2023 1:39:36 PM
Weighted Segment Value: 41.48

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	78	1	18	0.327	37	0.673	0	8	15
Segment: 2	6	0.6	5	0.5	1	0.1	0	0	0
Segment: 3	63	1	14	0.28	36	0.72	0	1	12
Segment: 4	15	1	3	0.3	7	0.7	0	1	4
Segment: 5	75	1	26	0.448	32	0.552	0	4	13
Segment: 6	44	1	11	0.333	22	0.667	0	5	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.4	3	0.3	1	0.1	0	3	0
Totals:	289	6	80	2.489	136	3.511	0	23	50

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Lori Frisk		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	Comments Submitted
1	Western Area Power Administration	Sean Erickson		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A

5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett	Megan Caulson	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A

1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Shawna Satterwhite	Negative	Third-Party Comments
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		None	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Negative	Third-Party Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Third-Party Comments

5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
3	Salt River Project	Mathew Weber		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A

1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
5	Bonneville Power Administration	Christopher Siewert		Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted

3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Salt River Project	Sarah Blankenship		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
6	AEP	Justin Kuehne		Negative	Comments Submitted
3	AEP	Kent Feliks		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	Comments Submitted

5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Emma Halilovic		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Affirmative	N/A
5	APS - Arizona Public Service Co.	Brandon Smith		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted

1	JEA	Joseph McClung	Negative	Third-Party Comments
3	APS - Arizona Public Service Co.	Jessica Lopez	None	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor	None	N/A
1	New York Power Authority	Salvatore Spagnolo	Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns	Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons	Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger	Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman	Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich	Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Daniel Herring	Affirmative	N/A
6	New York Power Authority	Shelly Dineen	Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry	Affirmative	N/A
1	Great River Energy	Gordon Pietsch	Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson	Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu	Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Melanie Wong	None	N/A
5	Manitoba Hydro	Kristy-Lee Young	Negative	Comments Submitted
10	New York State Reliability Council	Wesley Yeomans	Negative	Third-Party Comments
5	BC Hydro and Power Authority	Quincy Wang	None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu	Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez	Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service	Kathryn Tackett	Affirmative	N/A

	Co.				
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Negative	Third-Party Comments
1	Entergy	Brian Lindsey	Kristen Long	Affirmative	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Abstain	N/A
4	Electricities of North Carolina	Marcus Freeman		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
3	Entergy	James Keele		Affirmative	N/A
5	Salt River Project	Thomas Johnson		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		Abstain	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted

4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	JEA	John Babik		Negative	Third-Party Comments
1	Lower Colorado River Authority	Matt Lewis		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
1	M and A Electric Power Cooperative	William Price		None	N/A
					Third-

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Party Comments
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
1	Platte River Power Authority	Marissa Archie		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		Negative	Third-Party Comments
6	Western Area Power Administration	Chrystal Dean		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party

				Comments
5	LS Power Development, LLC	C. A. Campbell	None	N/A

[redacted]

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 IN 1 NB
Voting Start Date: 7/5/2023 12:01:00 AM
Voting End Date: 7/14/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 228
Total Ballot Pool: 277
Quorum: 82.31
Quorum Established Date: 7/14/2023 2:14:20 PM
Weighted Segment Value: 39.78

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	16	0.333	32	0.667	14	15
Segment: 2	6	0.5	4	0.4	1	0.1	1	0
Segment: 3	59	1	14	0.326	29	0.674	5	11
Segment: 4	14	1	3	0.3	7	0.7	1	3
Segment: 5	71	1	22	0.468	25	0.532	11	13
Segment: 6	42	1	12	0.414	17	0.586	6	7
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	7	0.4	3	0.3	1	0.1	3	0
Totals:	277	5.9	74	2.541	112	3.359	42	49

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	No Comment Submitted
5	AEP	Thomas Foltz		Abstain	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	No Comment Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Lori Frisk		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Negative	No Comment Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Negative	No Comment Submitted
1	Western Area Power Administration	Sean Erickson		Negative	No Comment Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A

4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	No Comment Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	No Comment Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	No Comment Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	No Comment Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		Negative	No Comment Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	No Comment Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	No Comment Submitted
4	Austin Energy	Tony Hua		Negative	No Comment Submitted
1	Austin Energy	Thomas Standifur		Negative	No Comment Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett	Megan Caulson	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	No Comment Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	No Comment Submitted
6	Public Utility District No. 2 of Grant	Mike Stussy		None	N/A

	County, Washington				
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	No Comment Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	No Comment Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer	Shawna Satterwhite	Negative	No Comment Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Negative	No Comment Submitted
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	No Comment Submitted
3	Tennessee Valley Authority	Ian Grant		None	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	No Comment Submitted
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
6	Salt River Project	Timothy Singh		Negative	No Comment Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	No Comment Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	No Comment Submitted

10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	No Comment Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	No Comment Submitted
1	Lakeland Electric	Larry Watt		Negative	No Comment Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	No Comment Submitted
3	Salt River Project	Mathew Weber		Negative	No Comment Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	No Comment Submitted
1	Avista - Avista Corporation	Mike Magruder		None	N/A
3	Exelon	Kinte Whitehead		Negative	No Comment Submitted
1	Exelon	Daniel Gacek		Negative	No Comment Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	No Comment Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		Negative	No Comment Submitted
5	Cowlitz County PUD	Deanna Carlson		Negative	No Comment Submitted

6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	No Comment Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	No Comment Submitted
6	Entergy	Julie Hall		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	No Comment Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	No Comment Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	No Comment Submitted
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	No Comment Submitted
5	Bonneville Power Administration	Christopher Siewert		Negative	No Comment Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	No Comment Submitted
6	Austin Energy	Imane Mrini		Negative	No Comment Submitted
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Negative	No Comment

					Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
1	National Grid USA	Michael Jones		Negative	No Comment Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	No Comment Submitted
3	Great River Energy	Michael Brytowski		Negative	No Comment Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	No Comment Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	No Comment Submitted
1	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	No Comment Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	No Comment Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Salt River Project	Sarah Blankenship		Negative	No Comment Submitted
6	Constellation	Kimberly Turco		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	No Comment Submitted

4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	No Comment Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	No Comment Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		None	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
6	AEP	Justin Kuehne		Abstain	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		None	N/A
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Negative	No Comment Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	No Comment Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	No Comment Submitted
6	Omaha Public Power District	Shonda McCain		Negative	No Comment Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	No Comment Submitted
6	Lakeland Electric	Paul Shipps		Negative	No Comment Submitted
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	No Comment Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	No Comment Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Negative	No Comment Submitted

3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	No Comment Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	No Comment Submitted
1	Hydro One Networks, Inc.	Emma Halilovic		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Negative	No Comment Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	APS - Arizona Public Service Co.	Brandon Smith		Negative	No Comment Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	No Comment Submitted
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	No Comment Submitted
1	JEA	Joseph McClung		Negative	No Comment Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		None	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	No Comment Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	No Comment Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	No Comment Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A

3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	No Comment Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	No Comment Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
10	New York State Reliability Council	Wesley Yeomans		Negative	No Comment Submitted
5	BC Hydro and Power Authority	Quincy Wang		None	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		Negative	No Comment Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	No Comment Submitted
3	Evergy	Marcus Moor	Alan Kloster	Negative	No Comment Submitted
3	Lakeland Electric	Steven Marshall		Negative	No Comment Submitted
1	Entergy	Brian Lindsey	Kristen Long	Affirmative	N/A
1	Taunton Municipal Lighting Plant	Devon Tremont		Negative	No Comment Submitted
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
3	Entergy	James Keele		Affirmative	N/A
5	Salt River Project	Thomas Johnson		Negative	No Comment Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	Pjoy Chua		Abstain	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Negative	No Comment Submitted
3	Omaha Public Power District	David Heins		Negative	No Comment Submitted

6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	No Comment Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	No Comment Submitted
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	No Comment Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Negative	No Comment Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	No Comment Submitted
5	JEA	John Babik		Negative	No Comment Submitted
1	Lower Colorado River Authority	Matt Lewis		Negative	No Comment Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	No Comment Submitted
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A

4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	No Comment Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	No Comment Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	No Comment Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	No Comment Submitted
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	No Comment Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	No Comment Submitted
1	M and A Electric Power Cooperative	William Price		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	No Comment Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
1	Platte River Power Authority	Marissa Archie		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		None	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	No Comment Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	No Comment Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	No Comment Submitted
5	Enel Green Power	Natalie Johnson		None	N/A
					No

5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comment Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	No Comment Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		Negative	No Comment Submitted
6	Western Area Power Administration	Chrystal Dean		Negative	No Comment Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A



A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-1**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:**

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority

is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Lower**	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified

						in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

			steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning	Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;

			by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service

			Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO]	6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	purposes. [BA, GO, LSE, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

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

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:

   a. add requirement identifying who provides and who receives data;
   b. identify acceptability;
   c. standard format;
   d. how to deal with new technologies (user written models if no standard model exists); and
   e. shareability.

4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving	See Implementation Plan

		MOD-032-1.	posted on the Reliability Standards web page for details on enforcement dates for Requirements.

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022
45-day formal or informal comment period with ballot	6/1/2023 – 7/17/2023

Anticipated Actions	Date
45-day formal or informal comment period with ballot	6/1/2023 – 7/17/2023
45-day formal or informal comment period with additional ballot	10/6/2023 – 11/20/2023
XX-day final ballot	
Board adoption	12/12/2023

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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing Real Power in non-isolated parallel operation with the Bulk Electric System.

- Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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 applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 the 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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required

						components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data

			Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within	Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability,

			the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource

			Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator	Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator	Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

				or Transmission Planner).	or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-2 – ATTACHMENT 1:

Data Reporting Requirements

The table below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [DP] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Demand [DP] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, DP]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Distribution Provider (DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc.) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	9. DC system models [TO] 10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP] 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
9. Distributed Energy Resource (DER) data[4] [DP, TO where DER is directly connected to the TO system and not through a DP][5] a. Location (bus from item 1) b. Real power capability c. Generator type (solar, battery, etc.) d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes. 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

[4] The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.

[5] Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022
45-day formal or informal comment period with ballot	6/1/2023 – 7/17/2023

Anticipated Actions	Date
~~45-day formal or informal comment period with ballot~~	~~6/1/2023 – 7/17/2023~~
45-day formal or informal comment period with additional ballot	10~~9~~/6~~1~~/2023 – ~~10~~11/~~15~~20/2023
XX-day final ballot	
Board adoption	12/12/2023

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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing ~~active power~~Real Power in non-isolated parallel operation with the Bulk Electric System.

- Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the standard applies to both Planning Authority and Planning Coordinator.~~

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar

days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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 applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 the 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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required

						components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data

			Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within	Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and	to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability,

			the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource

			Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~ R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~ R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator	Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~ R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator	Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~ R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

				or Transmission Planner).	or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-2 – ATTACHMENT 1:

Data Reporting Requirements

The table~~,~~ below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [DP~~, TO (when a Demand is not associated with a registered DP)~~] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Demand [DP~~, TO (when a Demand is not associated with a registered DP)~~] 6. Wind Turbine Data [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Distribution Provider (DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc.) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point*	7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, DP] 9. DC system models [TO] 10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP~~(when DER is not associated with a registered DP)~~] 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
c. fixed/switched shunt, if applicable d. in-service status* 9. Distributed Energy Resource (DER) data[4] [DP, TO where DER is directly connected to the TO system and not through a DP~~(when DER is not associated with a registered DP)~~][5] a. Location (bus from item 1) ~~and if DER feeder is subject to UFLS and/or UVLS~~ b. Real power capability ~~(minimum and maximum)~~ ~~c. Reactive power capability (minimum and maximum)~~ ~~d.~~c. Generator type (solar, battery, etc.) ~~e.~~d. ~~In-service date or other information to be used to make assumptions about~~ DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes. 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

[4] The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance~~The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance~~.

[5] Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022
45-day formal or informal comment period with ballot	6/1/2023 – 7/17/2023

Anticipated Actions	Date
~~45-day formal or informal comment period with ballot~~	~~6/1/2023 – 7/17/2023~~
45-day formal or informal comment period with additional ballot	10~~9~~/6~~1~~/2023 – ~~10~~11/~~15~~20/2023
XX-day final ballot	
Board adoption	12/12/2023

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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing Real Power in non-isolated parallel operation with the Bulk Electric System.

- Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Generator Owner

   4.1.3 ~~Load Serving Entity~~Distribution Provider

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.~~

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

   ~~MOD-032-2~~1, Requirement R1 ~~shall become effective on the first day of the first calendar quarter that is 12~~ 24 ~~months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-2~~1, Requirement R1 ~~shall become effective on the first day of the first calendar quarter that is 12~~ 24 ~~months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-2~~1, Requirements R2, R3, and R4 ~~shall become effective on the first day of the first calendar quarter that is 24~~ 36 ~~months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority~~

is not required, MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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.

~~"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. "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 ~~Assessment~~ Enforcement Program~~Processes~~: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

~~**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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required

						components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state,

			Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission	Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short	Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short	dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data

			Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

			or Transmission Planner).	than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

~~None.~~

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

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

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

reduce the quantity of MOD standards;

add short circuit data as a requirement to the MOD standards; and

supply data and models:

add requirement identifying who provides and who receives data;

identify acceptability;

standard format;

how to deal with new technologies (user written models if no standard model exists); and

a. shareability.

b. These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.

c. The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.

d. Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

e. Rationale for R2:

f. This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

g. **Rationale for R3:**

h. In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

i. This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and

cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts."* (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection-wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0,

			MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-~~01~~ 2 – ATTACHMENT 1:

Data Reporting Requirements

The table~~,~~ below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [~~LSE~~DP] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Demand [~~LSE~~DP] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), ~~Load Serving Entity~~Distribution Provider (~~LSE~~DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A ~~Load Serving Entity~~Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC system models [TO] 10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP] ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data~~-~~ [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
9. Distributed Energy Resource (DER) data[4] [DP, TO where DER is directly connected to the TO system and not through a DP] [5] a. Location (bus from item 1) b. Real power capability c. Generator type (solar, battery, etc.) d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes. ~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]		

[4] The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.

[5] Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.

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Implementation Plan

Project 2022-02 Modifications to TPL-001 and MOD-032
Reliability Standard MOD-032-2

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis

Applicable Entities

- Balancing Authority
- Generator Owner
- Distribution Provider
- Planning Coordinator
- Resource Planner
- Transmission Owner
- Transmission Planner
- Transmission Service Provider

NERC Glossary of Terms

This section includes a newly defined term used in the NERC Reliability Standard. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed New Definition(s):
Distributed Energy Resource (DER):

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing Real Power in non-isolated parallel operation with the Bulk Power System.

- Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

Background

As the penetration of distributed energy resources (DERs) continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Proposed Reliability Standard MOD-032-2 replaces the Load-Serving Entity as an applicable entity with the Distribution Provider and updates Attachment 1: Data Reporting Requirements with data specific to DERs.

General Considerations

In developing this implementation plan, the standard drafting team considered the time that would be necessary to develop data requirements and reporting procedures for data related to DERs, including identifying the proper reporting entity. The standard drafting team also considered that the standard would become applicable to the Distribution Provider for the first time.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource 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 MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4
Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Definition – Distributed Energy Resource (DER)
Where approval by an applicable governmental authority is required, the definition of Distributed Energy Resource (DER) shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1
Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance Dates

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032-2.

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Implementation Plan

Project 2022-02 Modifications to TPL-001 and MOD-032
Reliability Standard MOD-032-2

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis

Applicable Entities

- Balancing Authority
- Generator Owner
- Distribution Provider
- Planning Coordinator
- Resource Planner
- Transmission Owner
- Transmission Planner
- Transmission Service Provider

NERC Glossary of Terms

This section includes a newly defined term used in the NERC Reliability Standard. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Proposed New Definition(s):
Distributed Energy Resource (DER):

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing ~~active power~~Real Power in non-isolated parallel operation with the Bulk Power System.

- Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

Background

As the penetration of distributed energy resources (DERs) continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Proposed Reliability Standard MOD-032-2 replaces the Load-Serving Entity as an applicable entity with the Distribution Provider and updates Attachment 1: Data Reporting Requirements with data specific to DERs.

General Considerations

In developing this implementation plan, the standard drafting team considered the time that would be necessary to develop data requirements and reporting procedures for data related to DERs, including identifying the proper reporting entity. The standard drafting team also considered that the standard would become applicable to the Distribution Provider for the first time.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource 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 MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4
Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Definition – Distributed Energy Resource (DER)
Where approval by an applicable governmental authority is required, the definition of Distributed Energy Resource (DER) shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1
Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance Dates

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032-2.

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Unofficial Comment Form

Project 2022-02 Modifications to TPL-001 and MOD-032

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-02 Modifications to TPL-001 and MOD-032** by **8 p.m. Eastern, Monday, November 20, 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

Project 2022-02 addresses multiple Standard Authorization Requests (SARs) related to transmission planning and modeling data and analysis (MOD-032-1 Data for Power System Modeling and Analysis SAR from the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG); TPL-001-5.1 Transmission System Planning Performance Requirements SAR from NERC Inverter-Based Resource Performance Working Group (IRPWG); and TPL-001-5.1 Transmission System Planning Performance Requirements SAR from the SPIDERWG).

The Project 2022-02 Standard Drafting Team decided to break this project into two phases since there are two Reliability Standards involved and the project scopes are quite different. Phase one addresses MOD-032-1 in data collection and phase two will address TPL-001-5.1 in the accuracy of transmission system planning assessments. This posting affects phase one of this project only (MOD-032). TPL-001 will be addressed during phase two of this project.

Questions

1. Given the explanation in the Technical Rationale and response to industry comment, do you agree with the proposed definition for DER?

   ☐ Yes
   ☐ No

   Comments:

2. Are there any other clarifications needed in the Technical Rationale?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree the modifications made in MOD-032-2 will improve system modeling and reliability?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree the modifications made in MOD-032-2 are cost effective?

   ☐ Yes
   ☐ No

   Comments:

5. Do you agree with the Implementation Plan for revised MOD-032-2?

   ☐ Yes
   ☐ No

6. 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 2022-02 Modifications to MOD-032-2

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 MOD-032-2. 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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R1

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R2

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R3

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

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Technical Rationale for Reliability Standard MOD-032-2

October 2023

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. Items in Attachment 1 that were previously required to be provided by the LSE are now required to be provided by the DP. It is recognized that some distribution facilities do not have an associated DP that meets the NERC registration criteria. It is expected that TOs (or registered DPs) will need to coordinate with the owners of distribution facilities that do not have an associated NERC-registered DP to ensure the availability of the necessary data, either through interconnection agreements or other binding contracts.

The Standard Drafting Team (SDT) has concerns that there may be challenges in collecting data for DER connected to unregistered entities. Draft 1 proposed to assign this data obligation on the TO/DP, but based on industry comments, this may place an unreasonable compliance risk on the TO/DP because any unregistered entities that connect DER to their systems have no compliance obligation to provide data to the TO/DP. As such, the SDT recommends that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would unnecessarily delay the implementation of DER data requirements. The SDT believes there is value in moving forward with MOD-032-2 as it does provide substantial improvement with respect to ensuring DER data is available for inclusion in PC and TP studies.

Additionally, the SDT reviewed the dual applicability to Planning Authority and Planning Coordinator and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria is updated to use only a single term. The posted "Appendix 5B: Statement of Compliance Registry Criteria", dated January 19, 2021, still uses both terms and arguably, the Planning Authority term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the SDT excluded the explanatory language from MOD-032-2 applicability section.

Rationale for Distributed Energy Resource (DER) Definition

The SDT considered various DER definitions utilized in the industry and discussed in the SPIDERWG Terms and Definitions Working Document, including the six other definitions described in Appendix D which were not adopted by SPIDERWG. Through this review, the SDT determined each of these seven definitions

required or would benefit from refinement to be most suitable for the application in MOD-032 and more broadly.

The SDT consensus is that the proposed definition aligns with the intent of the SPIDERWG working definition for DER (which explicitly excludes demand response) and clarifies what is in scope and out of scope with respect to where DER is connected rather than the technology type. Utilizing the existing NERC definition for DP and the associated area of responsibility aligns with the scope of DER data collection and modeling activities and provides clarity for the industry to aid in gathering this information. It should be clear that MOD-032-2 applicability and compliance obligations refer to NERC-registered DPs; the use of the DP term in the DER definition does not in itself imply any compliance obligation.

Below is a summary of the rationale for the SDT departing from each of the seven definitions when proposing a new DER definition.

SPIDERWG definition
After considering the SPIDERWG definition, the SDT determined it provided a useful foundation but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term 1) included transient types of DER power beyond generation and storage; 2) pointed to a SPIDERWG-specific defined term for "distribution systems"; and 3) included sources of back-up power that would have no potential grid impacts.

The SDT chose to refer to generator and storage technologies specifically, rather than use the SPIDERWG language of "source", to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.) Additionally, by specifying facilities that produce Real Power, the scope is focused on only those facilities that may be exporting Real Power to the power system or offsetting Real Power load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load.

Further, the SDT term uses "connected to the Distribution Provider's system" to avoid ambiguities associated with a unique definition of "distribution system" as was required by the SPIDERWG term. The NERC glossary definition for DP[1] notes that the DP is defined by providing the distribution function (this includes entities that may not be NERC-registered DPs).

The SDT included the language "in non-isolated parallel operation with the Bulk Power System" to indicate that distributed energy resources with potential BES reliability impacts are those that have electrical connectivity to the BES. The SDT intentionally avoided the term "directly connected" to differentiate electrical connectivity from an electrical connection point. Resources that are only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BES and therefore are not of interest from a BES-reliability

[1] NERC Glossary of Terms, Updated March 2023. DP is definition: "Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."

perspective. The SDT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry.

IEEE 1547-2018
The SDT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the three issues identified above. The SDT incorporated the explicit reference to "generation and storage" aspect of the IEEE definition. Further, the IEEE concept of "capable of exporting active power to an EPS" was used to inform the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the SDT definition.

At the same time, the SDT did not view the IEEE definition as suitable for the SDT's intended use as written. The IEEE term qualifies the DER connection point as "not directly connected to a bulk power system" which the SDT viewed as potentially ambiguous. Instead, the SDT opted for the "connected to DP's system" language to point to a NERC defined term and concept. The SDT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a DER definition for inclusion in the NERC Glossary of Terms.

Federal Energy Regulatory Commission (FERC) Energy Primer
The SDT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability planning use cases, the SDT and SPIDERWG definitions target sources of electric power, with the SDT narrowing this definition to be only sources "capable of providing Real Rower". After considering the FERC definition, the SDT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)
NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the SDT concluded it is too broad. After considering the NARUC definition, the SDT determined it was not suitable for the intended use.

NERC DERTF
The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the SDT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric system" which the SDT views as ambiguous and overly broad. After considering the NERC DERTF definition, the SDT determined it was not suitable for the intended application.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be based on California legislation and includes energy efficiency, electric vehicles, and demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the SDT's use. After considering the CPUC definition, the SDT determined it was not suitable for the intended application.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition to exclude a large portion of DER (i.e. retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study. After considering the NYISO definition, the SDT determined it was not suitable for the intended application.

Rationale for Modifications to Attachment 1
MOD-032-2 Attachment 1: Data Reporting Requirements was updated with data specific to DERs. The intent is that all relevant DER data including both utility scale facilities (commonly referred to as U-DER) and smaller behind-the meter facilities (commonly referred to as R-DER) be available and represented in models of the interconnected transmission system consistent with the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum amount of information expected to be needed to reasonably represent DER in transmission system models. It is expected that aggregate DER (rather than individual DER facilities) would be represented in most Planning Coordinator/Transmission Planner (PC/TP) study models. However, footnote 4 explicitly allows the PC/TP to specify the level of DER data aggregation. This provides flexibility for local practices wherein the PC/TP may elect to apply DER aggregation assumptions rather than depend on the DP/TO to apply aggregation assumptions.

The PC/TP may have access to sufficient data for modeling certain DER through alternative means (e.g., direct registration of DER in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DER that are excluded from the DP/TO obligation for providing DER modeling data. This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.

The SDT intentionally maintained flexible language as to whether the underlying DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP/TO applying a combination of approaches to source the data. The PC/TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

The SDT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with the required DER data are only presented in the “steady state” column (though arguably such data is also relevant to “dynamics” and/or “short circuit”). The SDT concluded that this was appropriate and consistent with other “dynamics” line items such as “Wind Turbine Data” and “Photovoltaic systems” that are listed without detailed sub-bullets. Drastically altering the structure of Attachment 1 or explicitly adding DER data to the “short circuit” column was beyond the scope of the Project 2022-02 SAR. However, the PC or TP is not restricted from requiring any needed short circuit data in their joint modeling data requirements and reporting procedures developed per R1.

It should be noted that the modifications do not make DER a BES facility subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered DPs (or TOs) to

provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases. There are already existing requirements for DPs (or TOs) to provide information about load connected to their systems. Similar to load, DER is not generally considered to be a BES facility. However, BES reliability assessments require an accurate representation of both aggregate load and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient DER data is available to the PC/TP so that appropriate DER representations can be included in their BES reliability assessments.

- **Inferring DER Capabilities**

As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DER may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DER installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate ride-through characteristic representation for DER in that area could be inferred by the in-service date of the DER. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

- **Inclusion of Data Related to DER Subject to Trip by UFLS and/or UVLS**

There is a reliability need for the DP/TO to convey this information to the PC/TP. As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DER subject to each UVLS/UFLS tripping stage should be identified.

- **Inclusion of Aggregate Demand Clarification**

Footnote 2 was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DER is not consistent with a modeling framework that explicitly represents DER. In situations where DER is not separately metered, a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. A consistent reduction in load on the feeder may be indicative of DER interconnections.

- **Examples for Footnote 5**

Footnote 5 was added to Attachment 1, item 9, after the bracketed statement, indicating the functional entity responsible for data reporting requirements is the “DP, TO where DER is directly connected to the TO system and not through a DP”, to cover situations where the DER is not connected to a registered DP or directly to a registered TO. In these situations, DER is connecting to an “unregistered Distribution Provider”, that is responsible for DER interconnection processes and data management but does not have

NERC compliance obligations. The SDT viewed the collection of all DER data as the appropriate aim, but recognized practical constraints associated with unregistered entity compliance obligations. For that reason, the SDT added a footnote that in part states, "the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information" to request data that cannot be required.

The SDT offers two examples to illustrate the SDT's intended application of Footnote 5:

- If the DER is directly connecting to an unregistered Distribution Provider that is immediately electrically adjacent to a registered TO (i.e., "next closest electrically connected registered entity"), the TO is responsible for requesting data from the unregistered DP and incorporating it in the MOD-032 data to the Planning Coordinator.
- If the DER is directly connected to an unregistered Distribution Provider that is served by a registered DP (i.e., "next closest electrically connected registered entity"), then the registered DP is required to request data from the unregistered Distribution Provider and include this data in the MOD-032 data submission.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale for Reliability Standard MOD-032-2

~~May~~ October 2023

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. Items in Attachment 1 that were previously required to be provided by the LSE are now required to be provided by the DP. It is recognized that some distribution facilities do not have an associated DP that meets the NERC registration criteria. ~~In such instances, the specified data is required to be provided by the Transmission Owner (TO) or registered DP to which those facilities are connected.~~ It is expected that TOs (or registered DPs) will ~~may~~ need to coordinate with the owners of distribution facilities that do not have an associated NERC-registered DP to ensure the availability of the necessary data, either through interconnection agreements or other binding contracts.

The Standard Drafting Team (SDT) has concerns that there may be challenges in collecting data for DER connected to unregistered entities. Draft 1 proposed to assign this data obligation on the TO/DP, but based on industry comments, this may place an unreasonable compliance risk on the TO/DP because any unregistered entities that connect DER to their systems have no compliance obligation to provide data to the TO/DP. As such, the SDT recommends that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would unnecessarily delay the implementation of DER data requirements. The SDT believes there is value in moving forward with MOD-032-2 as it does provide substantial improvement with respect to ensuring DER data is available for inclusion in PC and TP studies.

~~Additionally, the standard drafting team (SDT) reviewed the dual applicability to Planning Authority and Planning Coordinator and determined that that the explanation from MOD-032-1 is still correct and valid with minor edits as proposed. The posted "Appendix 5B: Statement of Compliance Registry Criteria", dated January 19, 2021, still uses the Planning Authority term.~~Additionally, the SDT reviewed the dual applicability to Planning Authority and Planning Coordinator and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria is updated to use only a single term. The posted "Appendix 5B: Statement of Compliance Registry Criteria", dated January 19, 2021, still uses both terms and arguably, the Planning Authority term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the SDT excluded the explanatory language from MOD-032-2 applicability section.

Rationale for Distributed Energy Resource (DER) Definition

The SDT considered various DER definitions utilized in the industry and discussed in the SPIDERWG Terms and Definitions Working Document, including the six other definitions described in Appendix D which were not adopted by SPIDERWG. Through this review, the SDT determined each of these seven definitions required or would benefit from refinement to be most suitable for the application in MOD-032 and more broadly.

The SDT consensus is that the proposed definition aligns with the intent of the SPIDERWG working definition for DER (which explicitly excludes demand response) and clarifies what is in scope and out of scope with respect to where DER is connected rather than the technology type. Utilizing the existing NERC definition for DP and the associated area of responsibility aligns with the scope of DER data collection and modeling activities and provides clarity for the industry to aid in gathering this information. It should be clear that MOD-032-2 applicability and compliance obligations refer to NERC-registered DPs; the use of the DP term in the DER definition does not in itself imply any compliance obligation.

Below is a summary of the rationale for the SDT departing from each of the seven definitions when proposing a new DER definition.

SPIDERWG definition

After considering the SPIDERWG definition, the SDT determined it provided a useful foundation but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term 1) included transient types of DER beyond power beyond generation and storage; 2) pointed to a SPIDERWG-specific defined term for "distribution systems"; and 3) included sources of back-up power that would have nowithout grid potential grid impacts.

The SDT chose to refer to generator and storage technologies specifically, rather than use the SPIDER-WG language of "source", to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.) Additionally, by specifying facilities that produce Real Power, the scope is focused on only those facilities that may be exporting Real Power to the power system or offsetting Real Power load (e.g., residential solar or commercial rooftop solar, even if they only operate at unity power factor or don't have any reactive power capability). This would exclude examplestechnologies such as charging-only electric vehicle (EV) installations and controllable load options.

Further, the SDT term uses used "connected to the Distribution P'sProvider's system" to avoid ambiguities associated with defining aa unique definition of "distribution system" as was required by the SPIDERWG defintiondefinitionterm.

The NERC glossary definition for DP[1] notes that the DP is defined by providing the distribution function (this includes entities that may not be NERC-registered DPs).

The SDT included the language "in non-isolated parallel operation with the Bulk Power System." to indicate that distributed energy resources with potential BES reliability impacts are those that ~~are actually electrically connected~~ have electrical connectivity to the BES. The SDT intentionally avoided the term "directly connected" to differentiate electrical connectivity from an electrical connection point. Resources that are only operated in ~~an~~ islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BES and therefore are not of interest from a BES-reliability perspective. The SDT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry.

IEEE 1547-2018

The SDT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the three issues identified above. The SDT incorporated the explicit reference to "generation and storage" aspect of the IEEE definition. Further, the IEEE concept of "capable of exporting active power to an EPS" was used to inform the need for capturing non-isolated, long-term paralleling and the sourcing of R~~r~~eal ~~(i.e., active)~~ P~~p~~ower (i.e., active power) ~~-~~within the SDT definition.

At the same time, the SDT did not view the IEEE definition as suitable for the SDT's intended use as written. The IEEE term qualifies the DER connection point as "not directly connected to a bulk power system" which the SDT viewed as potentially ambiguous. Instead, the SDT opted for the "connected to DP's system" language to point to a NERC defined term and concept. The SDT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a DER definition for inclusion in the NERC Glossary of Terms.

Federal Energy Regulatory Commission (FERC) Energy Primer

The SDT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response)~~,~~ which is not aligned with the SPIDERWG definition. Given the reliability planning use cases, the SDT and SPIDERWG definitions target sources of electric power, with the SDT narrowing this definition to be only sources "capable of providing Real Rower". After considering the FERC definition, the SDT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)

NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the SDT concluded it is too broad. After considering the NARUC definition, the SDT determined it was not suitable for the intended use.

[1] NERC Glossary of Terms, Updated March 2023. DP is definition: "Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."

NERC DERTF
The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the SDT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric system" which the SDT views as ambiguous and overly broad. After considering the NERC DERTF definition, the SDT determined it was not suitable for the intended application.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be~~is~~ based on California legislation and includes energy efficiency, electric vehicles, and demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the SDT's use. After considering the CPUC definition, the SDT determined it was not suitable for the intended application.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition to exclude a large portion of DER (i.e. retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study. After considering the NYISO definition, the SDT determined it was not suitable for the intended application.

Rationale for Modifications to Attachment 1
MOD-032-2 Attachment 1: Data Reporting Requirements was updated with data specific to DERs. The intent is that all relevant DER data including both utility scale facilities (commonly referred to as U-DER) and smaller behind-the meter facilities (commonly referred to as R-DER) be available and represented in models of the interconnected transmission system consistent with the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum amount of information expected to be needed to reasonably represent DER in transmission system models. It is expected that aggregate DER (rather than individual DER facilities) would be represented in most Planning Coordinator/Transmission Planner (PC/TP) study models. However, footnote 4 explicitly allows the PC/TP to specify the level of~~require either aggregated or unaggregated~~ DER data aggregation. This provides flexibility for local practices wherein the PC/TP may elect to apply DER aggregation assumptions rather than depend on the DP/TO to apply aggregation assumptions.

The PC/TP may have access to sufficient data for modeling certain DER through alternative means (e.g., direct registration of DER in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DER that are excluded from the DP/TO obligation for providing DER modeling data. This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.

The SDT intentionally maintained flexible language as to whether the underlying DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data

availability or sufficiency issues, among other factors, may lead to the DP/TO applying a combination of approaches to source the data. The PC/TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

The SDT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with the required DER data are only presented in the "steady state" column (though arguably such data is also relevant to "dynamics" and/or "short circuit"). ~~The addition to the "dynamics" column was limited to the "Distributed Energy Resource (DER) data" line item~~. The SDT concluded that this was appropriate and consistent with other "dynamics" line items such as "Wind Turbine Data" and "Photovoltaic systems" that are listed without detailed sub-bullets. Drastically altering the structure of Attachment 1 or explicitly adding DER data to the "short circuit" column was beyond the scope of the Project 2022-02 SAR. However, the PC or TP is not restricted from requiring any needed short circuit data in their joint modeling data requirements and reporting procedures developed per R1.

It should be noted that the modifications do not make DER a BES facility~~ies~~ subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases. There are already existing requirements for DPs (or TOs) to provide information about load connected to their systems. Similar to load, DER is not generally considered to be a BES facility. However, BES reliability assessments require an accurate representation of both aggregate load and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient DER data is available to the PC/TP so that appropriate DER representations can be included in their BES reliability assessments.

- **Inferring DER Capabilities~~nclusion of In-Service Date or Other Information~~**

As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DER may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DER installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate ride-through characteristic representation for DER in that area could be inferred by the in-service date of the DER. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

- **Inclusion of Data Related to DER ~~Feeders~~ Subject to Trip by UFLS and/or UVLS**

There is a reliability need for the DP/TO to convey this information to the PC/TP. As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact

to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DER subject to each UVLS/UFLS tripping stage should be identified.

- **Inclusion of Aggregate Demand Clarification**

Footnote 2 was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DER is not consistent with a modeling framework that explicitly represents DER. In situations where DER is not separately metered, a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. A consistent reduction in load on the feeder may be indicative of DER interconnections.

- **Examples for Footnote 5**

Footnote 5 was added to Attachment 1, item 9, after the bracketed statement, indicating the functional entity responsible for data reporting requirements is the "DP, TO where DER is directly connected to the TO system and not through a DP", to cover situations where the DER is not connected to a registered DP or directly to a registered TO. In these situations, DER is connecting to an "unregistered Distribution Provider", that is responsible for DER interconnection processes and data management but does not have NERC compliance obligations. The SDT viewed the collection of all DER data as the appropriate aim, but recognized practical constraints associated with unregistered entity compliance obligations. For that reason, the SDT added a footnote that in part states, "the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information" to request data that cannot be required.~~n.~~"

The SDT offers two examples to illustrate the SDT's intended application of Footnote 5:

- ~~I~~if the DER is directly connecting to an unregistered Distribution Provider that is immediately electrically adjacent to a registered TO (i.e., "next closest electrically connected registered entity"), the TO is responsible for requesting data from the unregistered DP and incorporating it in the MOD-032 data to the Planning Coordinator.
- ~~I~~if the DER is directly connected to an unregistered Distribution Provider that is served by a registered DP (i.e., "next closest electrically connected registered entity"), then the registered DP is required to request data from the unregistered Distribution Provider and include this data in the MOD-032 data submission.

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Standards Announcement

Project 2022-02 Modifications to TPL-001 and MOD-032

Formal Comment Period Open through November 20, 2023

Now Available

A formal comment period for **Project 2022-02 Modifications to TPL-001 and MOD-032** is open through **8 p.m. Eastern, Monday, November 20, 2023** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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 standard and implementation plan, as well as the non-binding poll of the

associated Violation Risk Factors and Violation Severity Levels will be conducted **November 10 – 20, 2023**.

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 2022-02 Modifications to TPL-001 and MOD-032 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:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 2 - MOD-032-2
Comment Period Start Date:	10/6/2023
Comment Period End Date:	11/20/2023
Associated Ballots:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan AB 2 OT 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 AB 2 ST 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 AB 2 NB

There were 71 sets of responses, including comments from approximately 185 different people from approximately 114 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Given the explanation in the Technical Rationale and response to industry comment, do you agree with the proposed definition for DER?

2. Are there any other clarifications needed in the Technical Rationale?

3. Do you agree the modifications made in MOD-032-2 will improve system modeling and reliability?

4. Do you agree the modifications made in MOD-032-2 are cost effective?

5. Do you agree with the Implementation Plan for revised MOD-032-2?

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
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
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
					Jaimin Patal	Saskatchewan Power Corporation (SPC)	1	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Marc Gomez	Southwestern Power Administration (SWPA)	1	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					George Brown	Pattern Operators LP	5	MRO

					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Bryan Sherrow	Board Of Public Utilities (BPU)	1	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Public Utility District No. 1 of Chelan County	Anne Kronshage	6		Public Utility District No. 1 of Chelan County - Voting Group	Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	Ali Miremadi	CAISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					John Pearson	ISO New England, Inc.	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Elizabeth Davis	PJM	2	RF

					Charles Yeung	SPP	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
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
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Andy Fuhrman	Minnkota Power Cooperative, Inc.	1	MRO
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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
Southern Company - Southern Company Services, Inc.	Pamela Frazier	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
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern	6	SERC

						Company Generation		
					Leslie Burke	Southern Company - Southern Company Generation	5	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
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

Scott Brame	Scott Brame		SERC	NCEMC	Richard McCall	North Carolina Electric Membership Corporation	4	SERC
					Reid Cashion	North Carolina Electric Membership Corporation	5	SERC
					Chris Dimisa	North Carolina Electric Membership Corporation	3	SERC
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
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Sheri Maxey	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Mason Favazza	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc.	2	MRO
					Dee Edmondson	Southwest Power Pool Inc.	2	MRO

					Jim Williams	Southwest Power Pool Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool, Inc. (RTO)	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
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
					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

1. Given the explanation in the Technical Rationale and response to industry comment, do you agree with the proposed definition for DER?

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments which state:

we do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

We additionally do not agree or support the notion that from a NERC Reliability Standard compliance standpoint, entities should be held accountable for DERs that fall outside of the NERC registration criteria.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

We do not agree with the proposed definition for DER, nor do we agree that the definition for the term DER should be defined by the drafting team of single project working within the confines of that project as set forth by the Standard Drafting Process. We are concerned with the proliferation of NERC projects that are either directly, or indirectly, related to DERs and the potential consequences of the proposed DER definition. A definition that impacts multiple standards should be developed outside the scope of any individual standard and consider the impact to all of the affected NERC Reliability standards.

We have for example a GO/GOP-registered plant that feeds a DP-registered data center in behind-the-meter fashion, i.e. upstream of the POI to the TO. This 2.5 GW generation facility is clearly not a Distributed Energy Resource, yet it seems to be included under the currently proposed DER definition, depending on how one interprets the term, "parallel operation."

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 with the proposed definition for DER for the reasons stated by both EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports the MRO NSRF Comments.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
MRO NSRF does not agree with the proposed definition for DER; further, the MRO NSRF does not believe that the definition for the term DER should be defined solely by this Standard Drafting Team within the parameters of Project 2022-02. With the proliferation of NERC projects that are either directly, or indirectly, related to DERs, MRO NSRF contends that a definition, for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed in a separate project. Additionally, MRO NSRF has concerns that the proposed definition for DER may fall outside the purview of NERC Reliability Standards as allowed for by Section 215(a)(1) of the Federal Power Act (“The term [bulk-power system] does not include facilities used in the local distribution of electric energy.”).	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Entergy agree with NAGF comments. The NAGF does not agree with the proposed definition for DER, nor do we agree that the definition for the term DER should be defined by the drafting team of single project working within the confines of that project as set forth by the Standard Drafting Process. The NAGF is concerned with the proliferation of NERC projects that are either directly, or indirectly, related to DERs and the potential consequences of the proposed DER definition. A definition that impacts multiple standards should be developed outside the scope of any individual standard and consider the impact to all of the affected NERC Reliability standards.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
- MH recommends using “Bulk Power System” instead of “Bulk Electric System" - It is essential to explicitly state both exporting Real Power to the BPS and offsetting Real Power load. Proposed Definition: Generators and energy storage technologies connected to the Distribution Provider’s system that are capable of exporting Real Power or offsetting Real Power load in non-isolated parallel operation with the Bulk Power System.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	

Comment
Having two different defintions for Distribution Provider makes the scope confusing. The definition is too broad and we believe that there needs to be threshold for what constitutes a DER.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment
There needs further clarification if the DER is going to include every DER or there will be a threshold as there are several small projects that would be extremely costly to have to abide by each NERC mandated modeling and testing requirement when their impact to the BES is marginal. Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	

Comment
CenterPoint Energy Houston Electric, LLC (CEHE) does not support the development of an additional NERC Reliability Standard to define DER. CEHE finds the proposed revisions to MOD-032-2, too prescriptive and recommends that data reporting requirements for DERs listed in Attachment 1 be determined by the Planning Coordinator, in coordination with the Transmission Planner.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment

NV ENERGY does not agree with the proposed definition for DER; further, NV Energy does not believe that the definition for the term DER should be defined solely by this Standard Drafting Team within the parameters of Project 2022-02. With the proliferation of NERC projects that are either directly, or indirectly, related to DERs, NV ENERGY contends that a definition, for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed in a separate project.

Additionally, NV ENERGY has concerns that the proposed definition for DER may fall outside the purview of NERC Reliability Standards as allowed for by Section 215(a)(1) of the Federal Power Act ("The term [bulk-power system] does not include facilities used in the local distribution of electric energy.").

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye Power, Inc. supports the comments of ACES:

We at ACES applaud the attempt made by the SDT to clearly define what is by nature a nebulous concept; however, we feel that the current definition is overly broad and will create an insurmountable compliance obstacle.

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may not have a material impact to the reliability of the BES.

Additionally, there is a seemingly interchangeable use of the terms Distributed Energy Resource (DER) and Inverter Based Resource (IBR) to describe the same types of assets. It is our opinion that a singular definition should be developed to define these resource types. Given the currently proposed changes to the NERC Rules of Procedure (specifically Appendices 5A and 5B), we believe that the term IBR should be utilized in lieu of DER. Moreover, it is our opinion that the newly proposed GO-IBR and GOP-IBR registrations should be utilized when developing MOD-032-2. In short, we believe that the NERC registration criteria are well reasoned and were intentionally developed to only include those entities and/or resources that could have a material impact to the BES.

In conclusion, it is our recommendation that the proposed MOD-032-2 Reliability Standard be modified to include a non-zero MVA threshold. We believe that the DP should only be required to collect data from NERC registered entities.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES Clean Energy appreciates the Standard Drafting Team's research into the various DER definitions adopted across the industry and regions. However, with the introduction of a new definition from NERC, this will create additional confusion for entities, especially those that operate in regions where the term DER is currently utilized. AES Clean Energy recommends that the Standard Drafting Team take an approach of proposing a broader definition of DER that is not specific to MOD-032 and will be applicable to other on-going DER related standard projects before moving forward with MOD-032 changes. This is similar to that of Project 2020-06 where definitions of IBRs were proposed for industry feedback.

Likes 0	
Dislikes 0	

Response

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer

Answer	No
Document Name	

Comment

- Oncor Electric Delivery Company LLC ("Oncor") considers the DER definition used in the Technical Rationale for Reliability Standard MOD-032-2 too vague because it does not contain a voltage class threshold for an energy resource to be considered a DER.
- Oncor's view of DER is consistent with ERCOT's definition of DER, which is: "An electrical generating facility consisting of one or more on-site distributed generation units connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system." This definition can be found here: https://www.ercot.com/files/docs/2017/03/24/DER_OnePager_FINAL.pdf
- From Oncor's experience, the total capacity of the installation's on-site distributed generation units may exceed ten megawatts (MW); however, no more than ten MW of the installation's capacity will be allowed to export into the grid at any point in time at the point of common coupling.
- Is there any MW size threshold for Generator and energy storage technologies to be taken into account when the end-use customer is served at transmission voltage? We would prefer a MW size threshold be specified in the definition.

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	
David Rivera - New York Power Authority - 3	
Answer	No
Document Name	
Comment	
*NYPA appreciates the standard drafting team’s effort to define ‘**DER**’ and aligning it with IEEE 1547, but we believe a more detailed definition is essential for better interpretations. The current proposed definition seems too narrow, given the use of the term DER across multiple NERC standards. NYPA suggest SDT to propose a more detailed **DER** definition with examples to avoid potential misinterpretations as DER which is not solely for renewables.*	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
Likes 0	

Dislikes 0	
Response	
Bill Garvey - Dominion - Dominion Virginia Power - 3	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy's official response.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP recommends that the drafting team creates propose language in the Technical Rationale that suggests including the prosed definition in the Rules of Procedure (RoP- Appendix 2A) to ensure proper alignment with the NERC Glossary of Terms.

Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

ATC agrees that there is a need for a NERC DER definition, but ATC does not support the SDT's proposed definition for DER.

Defining DER within the confines of a single NERC project (i.e., NERC Project 2022-02) could limit the definition's use within other ongoing and future DER standard drafting efforts. With the number of NERC projects under modification and existing Standards that are either directly or indirectly related to DERs, ATC believes that a definition for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed outside the scope of any individual standard, and should consider the impact to any affected NERC Reliability standards.

If the SDT does go forward with a NERC Glossary of Terms definition for DER, the NERC definition of DER should not involve itself in facilities that do not fall under the purview and regulation of NERC (e.g., local distribution facilities).

ATC believes that the text "Distribution Provider's system" should not be referenced in the DER definition as it refers to the NERC glossary definition of Distribution Provider, not the NERC registered entity and in some cases this is different.

If the term "Distribution Provider" is used, ATC also suggests that there should be a clearer distinction between Distribution Provider as a NERC glossary term and Distribution Provider as a NERC registered entity.

As an alternative, the SDT could replace "connected to the DP's system" with "not directly connected to a bulk power system."

Additionally, ATC requests that the standard explicitly allows the PC to determine thresholds (ex: MW or MVA) for both the collection of DER data and for the modeling of DERs. Alternatively, thresholds for DER data collection and for DER data modeling could be included in the standard. Thresholds for DER data collection and for DER data modeling could also be included in the DER definition but this may be less appropriate/ flexible for future use.

DER thresholds greater than zero MW are needed to manage the potentially large administrative burden on NERC Registered Entities such as the TOs, TPs, and DPs.

ATC encourages a new NERC Registered Entity for DER (ex: DP-DER or IBR-DER) to bring DER data reporting accountability to those unregistered DPs with DER.	
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), NAGF and MRO NSRF for question #1.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
There needs further clarification if the DER is going to include every DER or there will be a threshold as there are several small projects that would be extremely costly to have to abide by each NERC mandated modeling and testing requirement when their impact to the BES is marginal. 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 does not agree with the proposed definition for DER, nor do we agree that the definition for the term DER should be defined by the drafting team of single project working within the confines of that project as set forth by the Standard Drafting Process. The NAGF is concerned with the proliferation of NERC projects that are either directly, or indirectly, related to DERs and the potential consequences of the proposed DER definition. A definition that impacts multiple standards should be developed outside the scope of any individual standard and consider the impact to all of the affected NERC Reliability standards.

In addition, the NAGF is concerned with the inconsistency of DER term used across the industry as stated in the examples provided in the Technical Rationale. Regions or even states have their own definition of DERs which may impact a Generator Owner's ability to comply with both NERC and other state or regional requirements. It is recommended that NERC perform outreach to regions and/or states to try to ensure some consistency on how the term is going to be used.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

The definition for the term DER should be defined solely by this Standard Drafting Team within the parameters of Project 2022-02. With the proliferation of NERC projects that are either directly, or indirectly, related to DERs. A definition, for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed in a separate project.

Additionally, the proposed definition for DER may fall outside the purview of NERC Reliability Standards as allowed for by Section 215(a)(1) of the Federal Power Act ("The term [bulk-power system] does not include facilities used in the local distribution of electric energy.").

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEi comments. The current proposed definition appears to conflict with how FERC has previously defined DER: “any resource located on the distribution system, any subsystem thereof or behind a customer meter”, which may include, but not limited to, “electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment”	
Likes 0	
Dislikes 0	
Response	
Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	
Comment	
NCEMC supports comment of ACES.	
Likes 0	
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
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 does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
Likes 0	
Dislikes 0	

Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	

Response
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment
As stated in our draft 1 comments, EEI does not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition. We additionally do not agree or support the notion that from a NERC Reliability Standard compliance standpoint, entities should be held accountable for DERs that fall outside of the NERC registration criteria.

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 applaud the attempt made by the SDT to clearly define what is by nature a nebulous concept; however, we feel that the current definition is overly broad and will create an insurmountable compliance obstacle. We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may not have a material impact to the reliability of the BES. Additionally, there is a seemingly interchangeable use of the terms Distributed Energy Resource (DER) and Inverter Based Resource (IBR) to describe the same types of assets. It is our opinion that a singular definition should be developed to define these resource types. Given the currently proposed changes to the NERC Rules of Procedure (specifically Appendices 5A and 5B), we believe that the term IBR should be utilized in lieu of DER. Moreover, it is our opinion that the newly proposed GO-IBR and GOP-IBR registrations should be utilized when developing MOD-032-2. In short, we believe that the NERC registration criteria are well reasoned and were intentionally developed to only include those entities and/or resources that could have a material impact to the BES. In conclusion, it is our recommendation that the proposed MOD-032-2 Reliability Standard be modified to include a non-zero MVA threshold. We believe that the DP should only be required to collect data from NERC registered entities.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

We at ACES applaud the attempt made by the SDT to clearly define what is by nature a nebulous concept; however, we feel that the current definition is overly broad and will create an insurmountable compliance obstacle.

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may not have a material impact to the reliability of the BES.

Additionally, there is a seemingly interchangeable use of the terms Distributed Energy Resource (DER) and Inverter Based Resource (IBR) to describe the same types of assets. It is our opinion that a singular definition should be developed to define these resource types. Given the currently proposed changes to the NERC Rules of Procedure (specifically Appendices 5A and 5B), we believe that the term IBR should be utilized in lieu of DER. Moreover, it is our opinion that the newly proposed GO-IBR and GOP-IBR registrations should be utilized when developing MOD-032-2. In short, we believe that the NERC registration criteria are well reasoned and were intentionally developed to only include those entities and/or resources that could have a material impact to the BES.

In conclusion, it is our recommendation that the proposed MOD-032-2 Reliability Standard be modified to include a non-zero MVA threshold. We believe that the DP should only be required to collect data from NERC registered entities.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment
The drafting team should consider defining “Transmission connected DERs” (100 kV and above) and “Distribution connected DERs” (below 100 kV). The proposed DER definition begins with “generators and energy storage technologies…”, implying that a Generator Owner is involved. The NERC Glossary of Terms defines a Generator Owner as the “Entity that owns and maintains generating Facility(ies)”. Would it be more practical to acquire DER data from the associated GO rather than the DP/TO; particularly in instances where the GO is a NERC registered entity?

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	

Comment
We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them. Also, It should say BES in front of "Generators" and before "energy storage technologies".

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	

Comment
Hi, please reference comments by Marty Hostler, NCPA Compliance Manager. Thank you, **Jeremy Lawson, P.E.** Generation Services Director of Engineering

Northern California Power Agency	
Likes 0	
Dislikes 0	
Response	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with the definition of DER. Texas RE noticed a potential contradiction within the technical rationale and would like it clarified. On page 2 of the technical rationale, it states “It should be clear that MOD-032 2 applicability and compliance obligations refer to NERC registered DPs; the use of the DP term in the DER definition does not in itself imply any compliance.” This seems to be contradicted on page 3, where it states: “The NERC glossary definition for DP1 notes that the DP is defined by providing the distribution function (this includes entities that may not be NERC-registered DPs).”	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	

The number of different DER definitions is confusing and difficult to work with. We agree with the proposed definition but it doesn't appear to be used consistently throughout the standard.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
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	
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	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
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	
Robert Follini - Avista - Avista Corporation - 3	
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	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 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; John Nierenberg, 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	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
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	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
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	
Document Name	
Comment	

RF recommends revising the proposed definition to explicitly include behind the meter resources:

“Generators and energy storage technologies connected to the Distribution Provider’s system, *either directly or behind the meter of an end use customer,* that are capable of providing Real Power in non-isolated parallel operation with the Bulk Electric System.”

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

The apparent use of a defined term for a registered entity (functional entity) may cause confusion in the industry. WECC appreciates the idea of trying to illustrate what the entity functions may be regardless of the determination for registration

Likes 0	
Dislikes 0	

Response

2. Are there any other clarifications needed in the Technical Rationale?

Jeremy Lawson - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

Hi, please reference comments by Marty Hostler, NCPA Compliance Manager.

Thank you,

Jeremy Lawson, P.E.

Generation Services Director of Engineering

Northern California Power Agency

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

While we do not agree with some of the SDT's viewpoints about the level of DER data required, we do appreciate the high level of effort made by the SDT to develop the Technical Rationale.

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

While we do not agree with some of the SDT's viewpoints about the level of DER data required, we do appreciate the high level of effort made by the SDT to develop the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

While EEI finds the Technical Rationale to be clear, we have concerns with the following statements and positions contained in the Technical Rationale:

Page 1; Rationale for Applicability Section:

EEI does not agree that TOs (or registered DPs) should be required to coordinate with the owners of distribution facilities that do not have an associated NERC-registered DP to ensure the availability of necessary data, either through interconnection agreements or other binding contracts. TOs and DPs have no ability to control interconnection agreements on other entity's system or the ability to obtain data from non-registered entities or facilities used in the local distribution of electric energy.

EEI is also concerned that the SDT acknowledges that data collection for DERs connected to unregistered entities is a problem and suggests that NERC should expand DP registration criteria or develop a DER-only DP registration criteria to address this gap but still believes there is value in moving MOD-032-2 forward with requirements for TOs and DPs when those obligations are limited to assets owned by the TOs and DPs.

Page 4 – Rational for Modifications to Attachment 1

EEI does not support the scope of modifications to MOD-032, Attachment 1 which obligates TOs and DPs to collect DER data on all relevant DERs including utility scale facilities and smaller behind the meter facilities, which appears to include all residential DERs even though these resources are used for local distribution.

EEI does not agree with the SDT's position that the PC/TP should have the authority to specify DER data to whatever level it deems appropriate. (Ref. the explanation of Footnote 4 from Attachment 1 of MOD-032).

The following statement (in boldface) should be struck from the Technical Rationale because TOs and DPs should have no obligation to provide any data related to DERs participating within a DER Aggregation in the organized markets. While the SDT appears to believe that while the data should be provided by the DER Aggregator, they believe that TOs and DPs still have an obligation to provide this data if requested to do so by the PC/TP: **This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.**

Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	

Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC appreciates the effort of the Standard Drafting Team in developing the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy’s official response.	
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	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
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	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No

Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES: While we do not agree with some of the SDT's viewpoints about the level of DER data required, we do appreciate the high level of effort made by the SDT to develop the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
NA	
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 agrees with the concerns expressed by EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No

Document Name	

Comment

FirstEnergy has concerns with the following statements and positions contained in the Technical Rationale:

Page 1; Rationale for Applicability Section:

EEI does not agree that TOs (or registered DPs) should be required to coordinate with the owners of distribution facilities that do not have an associated NERC-registered DP to ensure the availability of necessary data, either through interconnection agreements or other binding contracts. Such a requirement makes no sense. TOs and DPs have no ability to control interconnection agreements on other entity's system or the ability to obtain data from non-registered entities.

EEI is also concerned that the SDT acknowledges that data collection for DERs connected to unregistered entities is a problem and suggests that NERC should expand DP registration criteria or develop a DER-only DP registration criteria to address this gap but still believes there is value in moving MOD-032-2 forward with regulator obligations on TOs and DPs when it is recognized their ability to collect certain data is not possible.

Page 4 – Rational for Modifications to Attachment 1

EEI does not support the scope of modifications to MOD-032, Attachment 1 which obligates TOs and DPs to collect DER data on all relevant DERs including utility scale facilities and smaller behind the meter facilities, which appears to include all residential DERs even though these resources are used for local distribution.

EEI does not agree with the SDT's position that the PC/TP should have the authority to specify DER data to whatever level it deems appropriate. (Ref. the explanation of Footnote 4 from Attachment 1 of MOD-032).

EEI believes that the following statement (underlined) should be struck from the Technical Rationale because TOs and DPs should have no obligation to provide any data related to DERs participating within a DER Aggregation in the organized markets. While the SDT appears to believe that while the data should be provided by the DER Aggregator, they believe that TOs and DPs still have an obligation to provide this data if requested to do so by the PC/TP: This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.

Likes 0	
Dislikes 0	

Response

Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
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	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
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; John Nierenberg, 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	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Rivera - New York Power Authority - 3	
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	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
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	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them. Specifically, we disagree with the SDT stating in the standard footnote 5 on page 16, first sentence "Where DER is connected to an unregistered Distribution Provider". This makes it appear as though said entity should be registered. If they are not in the NERC registry then they are not a DP. Consequently, it should say "Where a DER is connected to a non-Distribution Provider". We also disagree with the SDT re: proposed standard footnote 5 on page 16, second sentence. "An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider". Our view is that this seems to imply that another DP or TO can determine, or has the responsibility of determining, if an entity should be registered as a DP. That is NERC's or the Regional Entities' responsibility; registration determination is not a DP's or a TO's responsibility.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The technical rationale doesn't provide guidance on determining which facilities connected to the DP's system would be classified as DERs and which ones would not. The current definition would classify any generation connected to a registered DP as a DER.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
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

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	Yes
Document Name	

Comment

The SDT should give consideration to paragraph 105 of FERC Order No. 901 which states that if distribution providers are unable to gather adequate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2

Answer	Yes
Document Name	2022-02 Unofficial_Comment_Form_SRC_11-20-23_FINAL_as filed.docx
Comment	

The **ISO/RTO Council Standards Review Committee (SRC)[1]** recommends that the Technical Rationale include an explanation of why the term reactive power capability (*see* Draft #1 of MOD-032-2, Attachment 1, steady-state item 9c) has been removed in favor of the language added in Draft #2 of MOD-032-2, Attachment 1, steady-state item 9d. Our understanding is the change was made to focus on broadening the language to better describe the data needed to model operating characteristics (including ride-through capability, voltage support, frequency control, etc.) instead of focusing on mere operating capabilities.

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO, MISO, NYISO, PJM, SPP and ISO-NE (except for the response to question 6). ERCOT supports the response to question 2 only.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	Yes
Document Name	
Comment	

Does the term "interconnection-wide" need to be capitalized.

Likes 0	
Dislikes 0	
Response	

Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller

Answer	Yes
Document Name	
Comment	

Black Hills Corporation does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.

Likes 0	
Dislikes 0	

Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.	
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 does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.	
Likes 0	

Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	

Comment
Please provide the reasoning for elimination of reactive power (see Draft #1 of MOD-032-2, Attachment 1, item 9c) in favor of the added language in Draft #2 of MOD-032-2, Attachment 1, item 9d.

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	

Comment
While we may disagree with some of the positions taken by the Standard Drafting Team, the NAGF appreciates the efforts the Standard Drafting Team put forth in developing the technical rationale. *In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry. The NAGF recommends that the Standard Drafting Team re-consider how to address the issues surrounding data collection from entities who have no obligation to comply.* *The NAGF recommends that the statement "Distribution Provider refers to the NERC glossary definition, not the NERC registered entity," be revised to be: "The term Distribution Provider in the DER definition includes all parties cited in the NERC Glossary definition of a Distribution Provider, some of whom may be registered as TOs and not as DPs. References to Distribution Providers in the requirements of MOD-032 pertain however only to entities registered as DPs."*

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	
Comment	
Clarification is needed on size of DERs applicable. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Both the Technical Rationale & the Standard need to address the following issue: If the TO/DP is required to report data that the DER owner has no obligation to provide, how does the SDT propose to eliminate this compliance risk in the interim while a permanent solution is developed.?	
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 NAGF for question #2.	
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	

- Getting the gross demand of a registered/unregistered DP's DER will require tracking and retention of their DER data for TO/TP. Managing this additional DER data will put an undue burden on TPs. We request that the DER be responsible for submitting data to the PC/TPs directly.
- As requested by Oncor in the previous comment period, clarification is needed by SDT on how to represent a single location with multiple types of DER.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	
Comment	

Clarification is needed on size of DER's applicable.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	
Comment	

Regarding non registered DPs, as stated in the technical rationale *"the SDT recommends that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would unnecessarily delay the implementation of DER data requirements. The SDT believes there is value in moving forward with MOD-032-2 as it does provide substantial improvement with respect to ensuring DER data is available for inclusion in PC and TP studies."* We do not agree that this would unnecessarily delay the implementation. We believe it is necessary to delay the implementation because of this. Please explain the justification for moving forward with this known ambiguity which will cause significant compliance risk and may not ultimately be feasible until the process to modify NERC registry criteria is completed.

Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

In the “Inclusion of Aggregate Demand Clarification” section, it is suggested a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. In an era of energy efficiency and significant load transformation, it is extremely difficult to differentiate DER additions vs. other factors contributing to changing feeder loads. This suggestion should be removed as it could lead to false DER aggregation assumptions.

Foot Note 5 is an attempt by NERC to force requirements onto unregistered entities via registered entities. This requirement places compliance risk on TO’s and DP’s to request data where there is no enforcement support. The comments also don’t explain what would happen if the unregistered DP doesn’t provide the requested data.

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

The addition of the wording to support Footnote 2: “In situations where DER is not separately metered, a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. A consistent reduction in load on the feeder may be indicative of DER interconnections. “

This may serve the purpose of determining approximate aggregate demand under item # 2 in Attachment-1, column-1 (steady-state), but won’t support item # 9 which requires generator type (solar, battery etc.) and DER capabilities.

The addition of footnote 5 seems to be confusing. This can be addressed in the joint PC/TP modeling data requirements and reporting procedures developed per R1 (after coordinating with applicable DPs/TOs).

Likes 0	
Dislikes 0	

Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The standard as written places an untenable compliance burden on NERC registered entities. The technical rationale notes the challenges in collecting DER data from unregistered DPs. It does not note or address in any way the challenges in collecting DER data from the unregistered DER owners connected to DPs. These unregistered DER owners have no obligation or requirement under NERC standards to provide data for modeling. Requiring that DPs provide modeling data for equipment they do not own and have no means to acquire data on leaves them in a position where they fail to comply with the standard through no fault of their own and despite their best efforts.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Please see our response to Question #3.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
While we may disagree with some of the positions taken by the Standard Drafting Team, the NAGF appreciates the efforts the Standard Drafting Team put forth in developing the technical rationale. In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the	

acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry. We recommend that the Standard Drafting Team re-consider how to address the issues surrounding data collection from entities who have no obligation to comply.

We also recommend that the statement “Distribution Provider refers to the NERC glossary definition, not the NERC registered entity,” be revised to be, “The term Distribution Provider in the DER definition includes all parties cited in the NERC Glossary definition of a Distribution Provider, some of whom may be registered as TOs and not as DPs. References to Distribution Providers in the requirements of MOD-032 pertain however only to entities registered as DPs.”

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

The standard needs to specify the size of DER that is required to model

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment	
Please see Texas RE’s answer to #1.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree the modifications made in MOD-032-2 will improve system modeling and reliability?

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 support the proposed changes to MOD-032-2 because many of the changes would obligate TOs and DPs to provide data that exceeds their ability to obtain. EEI further notes that during the Fall 2023 NPCC Compliance and Reliability Conference a presentation titled "Inverter Based Resource Work Plan" was given and appears to use data from a Berkeley National Laboratory Report. The presentation goes on to indicate that BES IBRs (75MW at ≥100kV) account for 84% and non-BES (≥20MW & ≤75MW at ≥100kV plus ≥MW at <100kV) account for an additional 14%; for a total of 98% of the IBRs currently interconnected on the grid. This data additionally indicates that small IBRs (<20MW at any kV) only account for 2% of the connected IBRs and if correct, would mean these resources would have no meaningful impact on the Reliability of the BPS. Moreover, in FERC Order No. 901 (Reliability Standards to Address Inverter-Based Resources), the Commission made it clear that the focus of changes to NERC Reliability Standards, as it relates to modeling of DERs, is to be limited data to aggregate data not granular details on a non-aggregated basis. Given the NPCC data and FERC Order No. 901, it would indicate that many of the proposed changes to MOD-032 are unnecessary for reliability. This would include modifications to MOD-032 that propose to provide PCs/TPs with the authority to request data that is overly granular and unnecessary to model the impacts of DERs on the BPS. IBRs that have a meaningful impact on the BPS should be registered. Once this has been done, PCs and TPs could seek the data they need directly from the registered resource, not the TOs or DPs that are unlikely to have the needed data. While we recognize the need to gather and model the impacts of DER resources on the distribution system, modeling should be limited to load demand and aggregate DER impacts/offsets. However, we do support obligating DER Aggregators who are participating in the organized markets to provide data on their aggregated resources to the PCs/TPs upon request. We do not support obligating TOs and DPs to gather non aggregated data, upon request.

Likes 0	
Dislikes 0	

Response

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

Things appear to be specultive at this point.

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 agree with the comments submitted by BC Hydro, especially pertaining to Footnote 5. We feel that the language in Footnote 5, and the Technical Rationale, do not support passing the compliance obligations of an “unregistered Distribution Provider” onto “the next electrically connected registered entity (DP or TO)”. If models are required for all DERs in the BPS, there is an increased chance of Planning Coordinators and Transmission Planners receiving inaccurate models (especially from “unregistered Distribution Providers”) as many Distribution Providers may not have the experience to model their DERs correctly which could pollute the base cases and diminish their quality.	
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 the modifications made in MOD-032-2 will improve system modeling and reliability for the reasons stated by both EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports the MRO NSRF Comments.	

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF believes that the modifications made to MOD-032-2 will have very limited impact on improving system modeling and reliability. The fact remains that, TOs and DPs have no ability to compel DER owners to provide the data that would be necessary to significantly improve system modeling and reliability. This provides (in our opinion) a likely scenario under which a NERC-registered entity may be held to have a compliance gap for the non-performance/compliance of a non-NERC-registered entity.

The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes every residential solar and commercial rooftop solar customer on the DP's systems. This would likely impose an immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Accurate modeling of significant DER facilities would improve system modelling and reliability. However, requiring the modeling of facilities where modeling data is not available could just as easily harm the reliability of the transmission system.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	No
Document Name	

Comment
Through various reports, NERC has displayed how IBR can have an impact on the BES, but it is unclear how the aggregation of smaller “R-DER” impacts the BES in a manor proportional to “U-DER”. Total aggregated R-DER penetration is far from equivalent to a few “U-DER” installations across a utility’s footprint. Much of the required information is not available to DP’s for smaller DER installations and the ability to require the information from interconnectors is authorized by RERRA entities. The assumptions required to try to model R-DER due to MOD-032-2 requirements could also lead to false confidence and support of the BES from R-DER sources. A threshold is needed, suggested at 1 MW, for DER installations to differentiate the discrete modeling of resources with steady state and dynamic information vs. aggregating DER below such threshold, providing gross nameplate values, and allowing the PC to determine approximated DER response to system events.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	

Comment
The benifit of this additional data will have to be explained better. We are unclear of why it is important. The scope should only include what is directly connecting into Transmission System.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	No
Document Name	

Comment
It depends on the applicability of generators. If there is a threshold then Constellation agrees on improvement to reliability but a blanket statement will be overly burdensome with minimal to no improvement on reliability for projects smaller than 20 MVA. Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CEHE believes the proposed revisions to MOD-032-2 are problematic and contradicts the existing data requirements that have already been established by the local Planning Coordinators in coordination with Transmission Planners. For example, in the ERCOT region, ERCOT defines these data requirements through the coordination with Transmission Planners as part of various regional working groups. The already defined data requirements do not align with the proposed revisions of the Data Reporting Requirements in MOD-032-2 (ex. Attachment 1, item 2, footnote 2). The current MOD-032-1 addresses and includes the requirements around DER data.

CEHE is in support of EEI's comment that the modifications made to MOD-32-2 "continue to obligate TOs and DPs to provide data that exceeds their ability to obtain." CEHE agrees with EEI in that if this data is needed, the resource owners should be registered and obligated to supply the data, not the TOs or DPs.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy believes that the modifications made to MOD-032-2 will have very limited impact on improving system modeling and reliability. The fact remains that, TOs and DPs have no ability to compel DER owners to provide the data that would be necessary to significantly improve system modeling and reliability. This provides (in our opinion) a likely scenario under which a NERC-registered entity may be held to have a compliance gap for the non-performance/compliance of a non-NERC-registered entity.

The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes every residential solar and commercial rooftop solar customer on the DP's systems. This would likely impose an immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.

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 the opportunity to comment, and offers the following.

1. While BC Hydro appreciates the intent of modifications made in MOD-032-2, BC Hydro is of the opinion that the intended improvement in system modeling and reliability cannot be realized, until the implementation of an effective and practical approach to collect accurate DER data in a timely manner and with a sufficient level of detail. This would be challenging due to the lack of any compliance obligations on unregistered DER owners. DP and TO may have some leverage, such as introducing obligations for DER owners to provide acceptable data for future DERs before they can be connected to the DP/TO systems. However, in the case of unregistered DER owners that are already connected to a TO/DP, the TO/DP will have an extremely limited ability to ensure a timely collection of such data, its accuracy, and sufficient level of detail.

2. The Footnote 5 of the Attachment 1 states that "Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information". This appears to set a mandatory requirement, which – as outlined above – would impose regulatory compliance obligations the TO and/or DP registered entity may be unable to meet.

Likes 0	
Dislikes 0	
Response	

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	No
Document Name	
Comment	

Clarification is needed with the changes outlined in Attachment 1 in the Steady-State column of Table-#9:

1. "b. Real power capability"
- Is this referring to the nameplate or approved capacity?
2. "c. Generator type (solar, battery, etc.)"
- Oncor recommends modifying this statement to give instructions on how to report a single location with multiple types of DER.
3. "d. DER capabilities related to ride through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes."
- Could the SDT elaborate on how frequency control would impact the Steady State modeling?

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	

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	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy’s official response.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No

Document Name	
Comment	

While SPP believes that the proposed modifications are a good step towards improving system modeling and reliability. However, we still have concerns around the appropriate data collection process pertaining to DERs.

We recommend that the UFLS-Only DP be added to the applicability section of the standard as these registered entities are just as likely to have DERs connected to their system. From our perspective, adding the UFLS-Only DP will eliminate the possibility of uncaptured DER load data if a DP does not have access to this data

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	

The modifications do not address the true reliability gap in that GOP and DPs are not by the NERC ROP obligated to align to a TP. The language should be adjusted in R2 to state that the BA et all shall provide... to the TP of the interconnected Transmission system.

Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	No
Document Name	
Comment	

ATC appreciates the intent of modifications contained in MOD-032-2. However, as Draft 2 of the Standard is written, TOs and DPs have no mechanism to compel the actual DER owners to provide the data that would be necessary to significantly improve system modeling and reliability.

Compliance-related questions:

Please clarify what the compliance implications are if a TO/ TP or DP requests the modeling data but does not receive it or if the data is inaccurate? Will showing that the TO/ TP attempted to request data be enough? Or that the TO/ TP utilized (or at least considered) the data received if no collection and modeling thresholds are set?

Please clarify how the TO/ TP or DP should be aware that DER are connected to an unregistered DP? The TO/ TP and DP would not have insight into those systems.

Please clarify the obligations of the TO/TP and DP in determining who is next closest electrically to each unregistered entity (DP or TO) as listed in Footnote 5? Does the TO/TP or DP need to reach out to the DER or to the unregistered DP for the information? Would the request for DER information be an annual process or triggered by something else?

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) and MRO NSRF for question #3.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

If DER penetration levels are high in a particular area, the changes in MOD-032-2 could have a positive impact on reliability. However, if DER penetrations are not high enough to impact the reliability of the BES, DPs and TOs will have added unnecessary administrative work and compliance burden for the purpose of checking a compliance box.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No

Document Name	

Comment

It depends on the applicability of generators. If there is a threshold then Constellation agrees on improvement to reliability but a blanket statement will be overly burdensome with minimal to no improvement on reliability for projects smaller than 20 MVA.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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; John Nierenberg, 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

The new requirements for DER data do not appear to directly correlate with the fields in existing modeling software such as the Composite Load Model (CMPLDWG). Tacoma would prefer for the Requirements to either align with existing modeling software, or for there to be a guidance document outlining what additional new software/model development needs to take place before the required DER can actually be utilized. The most significant concern is that there are often multiple installations of DERs connected to each substation, where each DER has unique ride-through and voltage control capabilities.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	No
Document Name	

Comment

The revisions should also note that if the Planning Coordinator or Transmission Planner can obtain the information directly from the generator based on individual ISO Tariff or other local requirements that the TO or DP does not need to provide information listed in Attachment 1. Suggested revision is redlined below.

For steady-state:

9. Distributed Energy Resource (DER) data [DP, TO where DER is directly connected to the TO system and not through a DP unless the generator is required to provide the data directly to the PC or TP based on individual Tariff or local provisions]

a. Location (bus from item 1)

b. Real power capability

c. Generator type (solar, battery, etc.)

d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.

For dynamics:

10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP, unless the generator is required to provide the data directly to the PC or TP based on individual Tariff or local provisions]

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

The modifications made to MOD-032-2 may have limited impact on improving system modeling and reliability. However, TOs and DPs have no ability to compel DER owners to provide the data that would be necessary to significantly improve system modeling and reliability. The changes create a likely scenario under which a NERC-registered entity may be held to have a compliance gap for the non-performance/compliance of a non-NERC-registered entity.

The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes every residential solar and commercial rooftop solar customer on the DP's systems. This would likely impose an immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No

Document Name	
Comment	
Black Hills Corporation believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.	
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 believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	

Answer	No
Document Name	
Comment	

Black Hills Corporation believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.

Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not support the proposed changes to MOD-032-2 because many of the changes would obligate TOs and DPs to provide data that exceeds their ability to obtain. EEI further notes that during the Fall 2023 NPCC Compliance and Reliability Conference a presentation titled “Inverter Based Resource Work Plan” was given and appears to use data from a Berkeley National Laboratory Report. The presentation goes on to indicate that BES IBRs (75MW at ≥100kV) account for 84% and non-BES (≥20MW & ≤75MW at ≥100kV plus ≥MW at <100kV) account for an additional 14%; for a total of 98% of the IBRs currently interconnected on the grid. This data additionally indicates that small IBRs (<20MW at any kV) only account for 2% of the connected IBRs and if correct, would mean these resources would have no meaningful impact on the Reliability of the BPS. Moreover, in FERC Order No. 901 (Reliability Standards to Address Inverter-Based Resources), the Commission made it clear that the focus of changes to NERC Reliability Standards, as it relates to modeling of DERs, is to be limited data to aggregate data not granular details on a non-aggregated basis. Given the NPCC data and FERC Order No. 901, it would indicate that many of the proposed changes to MOD-032 are unnecessary for reliability. This would include modifications to MOD-032 that propose to provide PCs/TPs with the authority to request data that is overly granular and unnecessary to model the impacts of DERs on the BPS. IBRs that have a meaningful impact on the BPS should be registered. Once this has been done, PCs and TPs could seek the data they need directly from the registered resource, not the TOs or DPs that are unlikely to have the needed data. While we recognize the

need to gather and model the impacts of DER resources on the distribution system, modeling should be limited to load demand and aggregate DER impacts/offsets. However, we do support obligating DER Aggregators who are participating in the organized markets to provide data on their aggregated resources to the PCs/TPs upon request. We do not support obligating TOs and DPs to gather non aggregated data, upon request.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them.

Also, we believe either a DP or TO who has another entity interconnecting with them has a marketing responsibility of modifying their Interconnection requirements if they deem it necessary for reliability in their BA.

Likes 0	
Dislikes 0	

Response

Jeremy Lawson - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

Hi, please reference comments by Marty Hostler, NCPA Compliance Manager.

Thank you,

Jeremy Lawson, P.E.

Generation Services Director of Engineering

Northern California Power Agency

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

AEP thanks the SDT for adding the text in footnote 5 which states "…Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through ***available*** information" and request that clarity be provided on exactly what is meant by "available information?" AEP believes that information that is requested (and perhaps even exists) but is not provided by the data owner should be considered unavailable. In addition, this scenario should be added to the others listed in the Technical Rationale document.

Notwithstanding the SDT's response to our previous suggestion, AEP continues to believe that the best path forward for this proposed standard would be for those entities providing power at a minimum threshold to be registered as a Functional Entities and to provide DER data. We recommend that the SDT establish an aggregate minimum threshold, similar to what was recently proposed by NERC in regard to IBRs. As is the case in existing standards where Generator Owners are obligated to provide similar data, entities who possess the needed DER data noted in the Attachment One revisions should likewise be registered and explicitly obligated to provide this data as well. While we are unsure if the existing Functional Entities classes are themselves sufficient, or if instead, a new class of Functional Entities might need to be considered and developed, the need nonetheless exists. NERC may wish to also consider the potential that such obligations could potentially cross Federal and State jurisdictional lines of responsibility, further illustrating the complexity-of and challenges-in developing obligations to obtain the DER data in the revised Attachment One.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

In principle, getting more "reasonably accurate" DER models into the regional models should help to improve reliability. There could be some risk to reliability if DER dispatch in models is higher than expected as this could mask load serving reliability issues. MOD-032 regional model building groups need to provide guidelines on what level of DER should be included in each seasonal model. Studying appropriate sensitivity cases should be part of TPL-001 scope.

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 believes that including DERs will improve system modeling and reliability.
Likes 0	
Dislikes 0	
Response
Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC
Answer	Yes
Document Name	
Comment
The latest draft of MOD-032 no longer requires reactive power information to be collected for DERs. While most smaller systems really only operate at unity, it is the belief of NCEMC having this information will allow planners to more accurately model Distributed Energy Resources, thereby improving grid reliability. Thus, NCEMC recommends that reactive power data collection for DERs be required by MOD-032.
Likes 0	
Dislikes 0	
Response
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2
Answer	Yes
Document Name	
Comment
The SRC believes there is an urgent need to move forward with collecting DER data now. Additional DER data collection activities will be needed as the penetration of DERs increases; however, these modifications are a step in the right direction and more can be done over time. The revisions should also note that if the Planning Coordinator or Transmission Planner will obtain the information directly from the generator based on individual ISO Tariff or other local requirements that the TO or DP may not need to provide information listed in Attachment 1. Suggested revision is redlined below.

For steady-state:

9. Distributed Energy Resource (DER) data [DP, TO where DER is directly connected to the TO system and not through a DP ***unless the generator will provide the data directly to the PC or TP based on individual Tariff or local provisions****]*

a. Location (bus from item 1)

b. Real power capability

c. Generator type (solar, battery, etc.)

d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.

For dynamics:

10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP, ***unless the generator will provide the data directly to the PC or TP based on individual Tariff or local provisions****]*

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

While the acquisition and utilization of DER data by the PC/TP for the purposes of power system modeling should enhance the PC/TP's ability to study future scenarios and develop plans accordingly, we are concerned with the future compliance interpretation for Requirement R4. That is, how might the ERO (or its designee) modify its expectation for Interconnection-wide case(s) in regard to DER data?

Likes 0	
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
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	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 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	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
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	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - 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	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
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 Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Do you agree the modifications made in MOD-032-2 are cost effective?

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	

Comment

Hi, please reference comments by Marty Hostler, NCPA Compliance Manager.

Thank you,

Jeremy Lawson, P.E.

Generation Services Director of Engineering

Northern California Power Agency

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	

Comment

We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them.

Additionally, the SDT has not stated a cost or benefit to said modifications. 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, simply someone says there is a reliability gap, or a risk, but does not provide estimated tangible reliability indices improvement numbers or a cost to fill the alleged gap or risk, is not good justification to create another costly administrative process.

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 our opinion that, as written, the proposed changes are not cost effective. It is our belief that requiring the DP to collect data for all DER/IBR resources, without regard to size and/or reliability impact, will create an unnecessary compliance burden and only provide a marginally increased reliability benefit.	
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 our opinion that, as written, the proposed changes are not cost effective. It is our belief that requiring the DP to collect data for all DER/IBR resources, without regard to size and/or reliability impact, will create an unnecessary compliance burden and only provide a marginally increased reliability benefit.	
Likes 0	
Dislikes 0	
Response	

Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	
Comment	
The latest draft of MOD-032 no longer requires reactive power information to be collected for DERs. While most smaller systems really only operate at unity, it is the belief of NCEMC having this information will allow planners to more accurately model Distributed Energy Resources, thereby improving	

grid reliability and potentially allowing for solutions which reduce cost by taking DER reactive power capability into account. Thus, NCEMC recommends that reactive power data collection for DERs be required by MOD-032.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
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. *The NAGF requests that the SDT address the process under MOD-032 to require the TP/PC to request data each year rather than require the GO to go look for and follow TP/PC process. If reliability is really the goal, an active request for data is likely to receive a much higher response rate than expecting those that need to supply information to go looking for when, where and how they need to provide it. The NAGF believes that it is extremely costly for hundreds of entities to go looking for information to determine when they need to provide data than it is for a few entities to send out emails requesting the information.*	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	

Comment
Inclusion of small DERs is extremely cost burdensome for Generator Owners. Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	

Comment
As previously stated, if DER penetration levels are high in a particular area, the changes in MOD-032-2 could have a positive impact on reliability. However, if DER penetrations are not high enough to impact the reliability of the BES, DPs and TOs will have added unnecessary administrative work and compliance burden for the purpose of checking a compliance box. Additionally, if the TO/DP is required to report data that the DER owner has no obligation to provide, the standard should address how the RE intends to handle situations where the unregistered Distribution Provider does not provide the requested data to the registered DP or TO. Otherwise, the TO/DP may be subject to fines and penalties for non-compliance related an issue that is beyond the control of the TO/DP.

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 for question #4.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

ATC does not believe that MOD-032-2 Draft 2 is cost effective as it is written. The requirements would likely impose a huge administrative burden on the NERC Registered DPs and TOs potentially requiring additional staff.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

Because so many issues around DERs, IBRs and ESRs remain unresolved and will be dependent upon final requirements for DERs, it is difficult to address the cost effectiveness of the MOD-32-2 modifications.

We do believe that software upgrades will be required to collect data on DERs, IBRs, and ESRs that have the potential to create cost increases for many in the industry.

Furthermore, we recommend the drafting team take into consideration evaluation the cost effectiveness from the FERC Order 2222 and IEEE Standards (1547 and 2800) perspectives.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute for Duke Energy’s official response.

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	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
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	

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	No
Document Name	
Comment	
• Cost-effectiveness depends on the level of assumptions TOs/TPs are allowed to make in the DER data modeling. If high precision in data collection is required, this will take a resource's time, which will increase costs.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES: It is our opinion that, as written, the proposed changes are not cost effective. It is our belief that requiring the DP to collect data for all DER/IBR resources, without regard to size and/or reliability impact, will create an unnecessary compliance burden and only provide a marginally increased reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV ENERGY does not agree that the modifications in MOD-032-2 are cost effective. As proposed MOD-032-2 would likely impose a immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
The effort required to model all DER’s, regardless of size, is considerable and likely not achievable with non-registered entities. This is likely an exercise until additional regulations are in place requiring information at appropriate levels.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Inclusion of small DER's is extremely cost burdensome for generator owners. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
The effort required to model all DER’s, regardless of size, is considerable and likely not achievable with non-registered entities. This is likely an exercise until additional regulations are in place requiring information at appropriate levels.	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
The effort required to model all DER's, regardless of size, is considerable and likely not achievable with non-registered entities. This is likely an exercise until additional regulations are in place requiring information at appropriate levels.	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
No it requires a huge amount of effort that is why we need to have a clearly defined scope and a better defined process for registering non-registered DPs.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
The administrative burden to provide accurate modeling of aggregated R-DER does not outweigh marginal modeling benefits. It is recommended NERC focus on utility scale DER and assuming little to no support from residential DER during system events. A compromise may be to add a threshold for the steady state and dynamic modeling requirements in MOD-032-2 and allow all other DER to be aggregated gross nameplate values reported by DP/TO entities which the PC can determine modeling parameters for based on industry research.	
Likes 0	

Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
It's unclear how much work will be needed to develop the models. We don't see the modifications made since the last draft is changing the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We will not be able to assess the cost effectiveness of this process until the resulting procedure changes at MISO are finalized and we understand data requirements.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
MRO NSRF does not agree that the modifications in MOD-032-2 are cost effective. As proposed MOD-032-2 would likely impose a immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.	
Likes 1	Lincoln Electric System, 5, Millard Brittany

Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports the MRO 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 the modifications made in MOD-032-2 are cost effective for the reasons stated by both EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
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	

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Things appear to be specultive at this point.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until the intent of obligations assigned to the Applicable Entities are clear, FirstEnergy cannot determine the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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; John Nierenberg, 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	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
We offer no opinion on the cost effectiveness of the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	
Answer	
Document Name	
Comment	
No comment.	
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	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
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 will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren has no comments on cost effectiveness of this project	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the Implementation Plan for revised MOD-032-2?

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

Until the intent of obligations assigned to the Applicable Entities are clear, FirstEnergy cannot support the Implementation Plan.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP believes additional time will be needed to accommodate the work pertaining to assets newly brought into scope. Rather than being required to comply with the obligations 12 months after the definition has become effective, we instead suggest it be 24 months after the definition has become effective.

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 with the Implementation Plan for the reasons stated by both EEI and the MRO NSRF.

Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports the MRO NSRF Comments.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It The PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide the data to the PC/TP. The Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
If MOD-032-2 is approved as-is, utilities will need to increase resourcing to accommodate the additional modeling complexities and data collection. DP's, in particular, may not have staffing experience in dynamic modeling, which would lead to a need to establish contractors with the experience or hire/train internal staff. The ability to request the level of information to create dynamic models of DER also falls to the authority of RERRAs. Depending on the existing interconnection procedures, state or local government authorities may need to approve revisions to interconnection requirements. 12 months after the approval date is too soon to require compliance.	

Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DER definition needs to be clarified first.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not support of the proposed changes to MOD-032-2 and therefore cannot support the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It The PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide the data to the PC/TP. The Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.	

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye Power, Inc. supports the comments of ACES:

The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It is surprising to us that the PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide it to the PC/TP. We believe that the Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

Based on the rationale provided in our response to Question 3 above, BC Hydro is unable to support the proposed Implementation Plan at this time.

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	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy’s official response.	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP recommends that the implementation of Requirements R2, R3 and R4 become effective 24 – 36 months after the implementation of Requirement R1. In order for industry to implement these changes we believe it will require a large transitional curve for requesting and providing the data. Newly impacted entities will need time to transition and ensure that the new process is efficient and reliable.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
While ATC does not have any particular concerns with the timing outlined in the implementation plan as proposed, we are opposed to the rest of the standard and DER definition as written, and its associated responsibilities, we therefore do not agree with the implementation plan of the proposed version.	
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 for question #5.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

It is not prudent to agree with the implementation plan until the standard addresses how the RE intends to handle situations where the unregistered Distribution Provider does not provide the requested data to the registered DP or TO.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It The PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide the data to the PC/TP. The Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	
Comment	
NCEMC support comments of ACES.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

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

The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It is surprising to us that the PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide it to the PC/TP. We believe that the Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI does not support the proposed changes made to MOD-032 and therefore cannot support the Implementation Plan at this time as a result.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It is surprising to us that the PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide it to the PC/TP. We believe that the Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

As explained in our comments on Draft 1, we suggest the implementation plan be revised to allow 24 months (rather than 12 months) after the effective date for the initial performance of R2, R3 and R4. The drafting team's "expectation" that TOs and DPs would participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of R1, thereby allowing TOs and DPs to start working on data collection processes and methods more than 12 months prior to the effective dates of R2, R3, and R4 is not assured.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	No
Document Name	
Comment	
It should not be implemented as currently drafted and until a cost benefit analysis is provided.	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Hi, please reference comments by Marty Hostler, NCPA Compliance Manager. Thank you, **Jeremy Lawson, P.E.** Generation Services Director of Engineering Northern California Power Agency	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes

Document Name	
Comment	
Constellation has no additional comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern supports the comments by EEI on potential implementation challenges.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
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	
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	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
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	
Robert Follini - Avista - Avista Corporation - 3	
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	
Mike Magruder - Avista - Avista Corporation - 1	
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	
Ruchi Shah - AES - AES 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	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - 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	
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; John Nierenberg, 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	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
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	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
Hard to tell at this point.	
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	

6. Provide any additional comments for the standard drafting team to consider, if desired.

Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	
Document Name	

Comment

We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them.

Area coordinators are already responsible for submitting data for modelling, they should be getting data they feel they need; not what some other entity tells them they should get. If a PA needs data they should be responsible for getting said data.

Further, if said data is needed, then the BA and/or the TO or DP should modify and/or enforce their market and/or interconnection rules to require load and/or generation entities (Utilities interconnected to a BA's area) provide said data. It appears we are trying to draft new standards continent wide for local issues.

Additionally, each Utility is already required to complete an EIA-861 form annually. We suggest that the entity needing said data use data that is already on those spreadsheets and use a macro to populate each year's data (which EIA already has) with the bus numbers for each utility so it can be used with a composite load model for each bus.

The entity needing the data can call each utility or the TO that services them in order to get the appropriate bus number.

We feel there is more man-hours being spent talking about the issue and trying to develop a standard then it would take the entity that wants the data to call and find out the bus numbers to assign to data that already exists. Then the entity needing said data can get it annually from the public EIA website and run a macro to insert the bus numbers. Much simpler and less costly for everyone.

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	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

Comments on "Attachment 1":

Footnote 2 is concerning since the way we collect and forecast aggregate load data is metering that is unaware of any DER impacts. The suggestion in the technical rationale isn't possible to do cleanly. ("*In situations where DER is not separately metered, a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. A consistent reduction in load on the feeder may be indicative of DER interconnections.")*

We would prefer the standard more explicitly allow for estimation by either reported DER nameplate capacity, or by estimated % of load (i.e., if no better information is available, perhaps use the data you do have to estimate DER as a % of peak load).

Dynamics reporting requirement # 10 reads:

"*Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP]*"

The added detail here is more burdensome, and is almost certainly not going to be available. The technical rationale says:

"*The SDT intentionally maintained flexible language as to whether the underlying DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources*."

However the addition of requirements for more specific data seems to go against the characterization that "estimated quantities" are acceptable.

Steady-state reporting requirement #9 has a footnote 4 that reads:

"*The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.*"

The implication here about determining the equivalent distribution system impedance to DER is perplexing. First because steady-state models do not model distribution impedance. In most cases, everything (including the main distribution transformers) is lumped into the aggregate load. This does apply to dynamic load models that consider equivalent distribution system impedances, but there is no practical way to vary that for every DER. And this is inconsistent with the approach used to model motor loads. For example, there is no requirement to report every individual motor and the equivalent impedance to that motor. And one could argue that the motor load has a vastly more important effect on the system than DER. TPL-001-5.1 stipulates the use of dynamic load models for Stability analysis but allows for the use of an aggregate System Load model. No further details or requirements. Studies are extremely sensitive to the load model that's used. If it is okay to develop those load models in estimated, aggregate form, why should there be anything more expected for DER?

Our general feeling is that the proposed modifications for DER data is getting too detailed and there needs to be very clear and explicit language that says estimating aggregate DER data is acceptable if more detailed data is not available.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

The phrase "where DER is directly connected to the TO system and not through a DP" in steady state item 9 (and dynamics item 10) from Attachment 1 may not be consistent with footnote 5. ERCOT recommends simplifying the responsibility assignment in steady state item 9 (and dynamics item 10) to "[DP, TO]" and modifying footnote 5 to read as follows:

The registered entity (TO or DP) to which DER is connected is responsible for reporting DER data in accordance with PC/TP modeling data requirements and reporting procedures developed under Requirement R1. Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPC signed on to ACES comments:

We have a great deal of apprehension as it relates to proposed language in Footnote 5 of Attachment 1. Footnote 5 states (emphasis added):

"Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column."

By what method should it be determined which registered entity is the "next closest electrically connected". Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the "next closest electrically connected" and how? In order to make this determination, a certain amount of knowledge about the other entity's infrastructure is required.

Of even greater concern is the continued inclusion of data from unregistered entities despite the open acknowledgment by the SDT of the challenges with collecting said data (see Technical Rationale, paragraph 2). We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved and can be included in the next draft of MOD-032-2.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment

EEI notes that this project has been listed as a low priority project. While we understand this may have some immediate impacts on the work being conducted by this SDT, we suggest that a two phased approach for the revision of MOD-032 might address the immediate concerns surrounding efforts to align registration under Project 2017-02. Phase 1: Consider completing the work from project 2017-02 Standards Alignment with Registration: Replace Load-Serving Entity (LSE) with Distribution Provider (DP), remove the Planning Authority (PA) functional entity name and keep the Planning Coordinator (PC) functional entity name, and make the associated LSE / DP functional changes to the standard requirements. Phase 2: Please consider addressing additional DER data requirements, after further discussion regarding how GO-IBR and GOP-IBR standards are going to be addressed and what is needed from Distribution Providers regarding unregistered IBRs.

In addition to the comments responding to the questions above and our suggests related to project phasing, we are additionally concerned with Attachment 1, Footnote 5 and suggest it should be deleted because the next closest DP or TO to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.

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

We have a great deal of apprehension as it relates to proposed language in Footnote 5 of Attachment 1. Footnote 5 states (emphasis added):

“Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the “dynamics” column.”

By what method should it be determined which registered entity is the “next closest electrically connected”. Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the “next closest electrically connected” and how? In order to make this determination, a certain amount of knowledge about the other entity’s infrastructure is required.

Of even greater concern is the continued inclusion of data from unregistered entities despite the open acknowledgment by the SDT of the challenges with collecting said data (see Technical Rationale, paragraph 2). We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved and can be included in the next draft of MOD-032-2.

Additionally ACES collected the following comments for the consideration of the SDT:

1. "Once the GO-IBR standards are in place, the DP should not be part of this equation at all. This is especially true of non-registered members. Put the burden onto the GO-IBR not the DP."

2. "The latest draft of MOD-032 no longer requires reactive power information to be collected for DERs. While most smaller systems really only operate at unity, it is the belief of NCEMC having this information will allow planners to more accurately model Distributed Energy Resources, thereby improving grid reliability. Thus, NCEMC recommends that reactive power data collection for DERs be required by MOD-032."

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	
Document Name	

Comment

The SDT should give consideration to paragraph 105 of FERC Order No. 901 which states that if distribution providers are unable to gather adequate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation.

Southern supports the comments by EEI on potential implementation challenges.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon concurs with the comments submitted by the EEI.

Exelon suggests the drafting team consider allowing TP/PCs to establish a threshold for aggregate DER reporting. Certain types of DERs such as non-exporting, or DERs connected behind the meter as load offsetting DERs may not be of concern to the TP/PC should be exempt from DP/TO data collection and reporting requirements. Data collection and reporting requirements should focus on "front of meter" connected DERs who primarily export energy, or DERs participating in wholesale markets.

Additionally, FERC Order 2222 will require some level of DER data reporting and modeling that may result in the proposed changes to MOD-032 becoming duplicative of, and in some cases in conflict with, obligations imposed by Order 2222.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2

Answer	

Document Name	2022-02 Unofficial_Comment_Form_SRC_11-20-23_FINAL_as filed.docx

Comment

The SRC offers the following additional comments and recommendations:

Ensure consistency between Attachment 1, footnote 5 and steady-state item 9: The SRC is concerned that steady-state item 9 in Attachment 1 may not be consistent with footnote 5. Item 9 addresses instances in which DER is directly connected to a TO or DP, while footnote 5 addresses instances in which DER is not directly connected to a NERC-registered entity. Rather than addressing these topics in two separate locations, the SRC recommends that the drafting team ensure consistent language is used to describe each topic and consider addressing both topics in the same location, such as by moving relevant language from item 9 down to footnote 5.

The SRC recommends the SDT review and standardize its use of "DER" throughout the document. For example, MOD-032-2, Attachment 1, item 9 states:

Distributed Energy Resource (DER) data4 [DP, TO where DER is directly connected to the TO system and not through a DP (when DER is not associated with a registered DP)]5

However, this description of DER as "*DER is directly connected to the TO system and not through a DP*" appears to conflict with the DER definition (on page 2) which states: "*Generators and energy storage technologies connected to the Distribution Provider's system…*" To the extent a TO can also serve as a Distribution Provider and a DER is connected to the DP portion of a TO's system, there is no need to refer to that entity as a "TO" as the standard would apply to them as a DP.

Alternatively, if DERs can also be directly connected to a TO system, then the Distributed Energy Resource (DER) definition needs to be updated to reflect that as detailed below:

*Generators and energy storage technologies connected to **either a Transmission Owner's system or a** Distribution Provider's system that are capable of providing Real Power in non-isolated parallel operation with the Bulk Electric System.*

· Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

Stay within NERC's purview and require NERC-registered entities to provide DER information: To keep this project moving forward, the SRC recommends the SDT maintain its scope within NERC's regulatory purview. Requiring NERC registered entities to request information from non-registered entities as in Attachment 1, Footnote 5, moves the burden from entities that own and control the data to entities who do not own or control DER data. Entities are free to request information at any time without a standard. Using a mandatory standard to require an entity to request data is of little to no value. **The benefit of a mandatory standard lies in placing a requirement on the appropriate entity to provide the data**. Without a requirement on the providing entity, the data collected may be garbage and lead to poor modeling results; i.e. garbage in/garbage out.

As DERs proliferate, this increases the risk, administrative burden and cost on registered entities to expend time and energy on requesting and passing through DER data from unregistered entities that have no obligation to provide it ("pull" method). As non-registered entities have no obligation to provide the data or ensure its quality, this process may translate into a costly proposition that leads to poor modeling results. If the goal is to obtain quality data for modeling, NERC must ensure that it has the appropriate registration criteria and rules in place to require applicable NERC registered entities to provide it ("push" method) to modeling entities.

Footnote 5: *Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.*

Review the adequacy of Distribution Provider registration criteria. As noted in the **Technical Rationale for Reliability Standard MOD-032-2** and in Attachment 1, Footnote 5, the SRC observes that in some cases, the entity that owns and controls the DER information may not be a NERC-registered DP. In fact, in July 2018 NERC relaxed its Distribution Provider registration criteria which allowed certain entities to deregister as Distribution Providers,[1] thereby removing what would otherwise have been in place to compel a broader scope of entities to provide DER data.

To that end, NERC has the obligation to ensure all Distribution Providers with the ability to impact the reliability of the BES are registered. Therefore, NERC should verify whether its existing DP registration criteria is adequate to ensure reliable modeling. As with the registration of IBRs (where the approach proposed under Docket RD22-24-000 is expected to result in approximately 98% of BPS-connected IBR nameplate capacity being subject to applicable NERC Reliability Standards), existing DP registration requirements should likewise be made adequate to acquire needed DER information.

Although NERC may not be able to address this now, NERC should nonetheless commit to a plan to perform this validation as it would be helpful to know whether the existing registration criteria for a "Distribution Provider" is sufficient to capture a predominance of DERs. If not, NERC could develop and implement a plan to register DPs that would close the gap. In this way, this effort will not delay the SDT from moving forward with proposed modifications to MOD-032-2 now, as acquiring some DER information now will provide substantial improvement in PC and TP studies.

Standardize the required level of aggregation: The SRC is concerned if the standard does not specify or standardize "the required level of aggregation" among PC/TPs. The reason for this is to ensure future compliance audits will have an established aggregation level and removes any ambiguity of "the required level of aggregation" between the PC/TP being audited and the auditor.

Footnote 4 "*The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and **the required level of aggregation**. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.*"

Ensure comprehensive reporting: The SRC is concerned with the proposed written language as it allows a gap as to knowing whether or not the registered DP or non-registered DP is providing all information and data – leaving an unknown compliance responsibility. This is especially true for non-jurisdictional entities, where the data may be unverifiable (un-auditable) and would lead to additional compliance concerns. One possible remedy is to aggregate small generators of the same type, along with an optional MW threshold for reporting.

[1] **ERO Enterprise Registration Practice Guide:** Distribution Provider "directly connected" Determinations Version 2: July 5, 2018

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

In Attachment 1 please capitalize "interconnection-wide" in the following sentence: "Data must be shareable on an **interconnection-wide** basis to support use in the **Interconnection-wide** cases."

Did the SDT intend to have the TO(s) gather Item 1 in the "short circuit" column of the table in Attachment 1 for DERs (Item 9 in "steady-state" column)?

Has the SDT collaborated with Project 2022-04 EMT Modeling SAR team on any possible changes to MOD-032 that could be promoted now versus waiting to re-open MOD-032?

Attachment 1 Footnote 5- Determining the "next closest electrically connected entity" is very broad and subject to interpretation especially if deep within multiple jurisdictions (TO and DP or multiples of each). What mechanism is in place for registered DPs and TOs to ensure that data is collected appropriately for a non-registered DP? "Appropriately" may mean avoiding a couple of scenarios---Accounted for twice or more (once by a TO AND once or more by one or more registered DPs) or not accounted for at all by either the DP or TO. Is the SDT leaving the determination of "next closest electrically connected entities" to the TP or PC?

Additionally, would recommend a footnote 5 (or 6) be added to Item 10 in the “dynamics” column to provide clarity versus referring to item 10 within the footnote itself.

For Item 9 in “steady-state” column (i.e., DER data). WECC would suggest changing “Generator type (solar, battery, etc.)” to be more reflective of the proposed definition of DER which starts out as “Generators and energy storage technologies…”. Consider removing “Generator” from 9c and simply say “Type (solar, battery, etc.)”

The SDT should consider utilizing or correcting Glossary of Term usage within Table 1 to reflect “Real Power” and “Reactive Power” for all parts of the table to provide clarity.

Further comments for Question 1: The addition of the phrase “Distribution Provider refers to the NERC glossary definition, not the NERC registered entity” may cause confusion as the ROP definition of the registered entity (DP) is the same as the Glossary of Terms. SDT should further consider if a different term should be utilized to avoid some confusion. WECC appreciates the idea of trying to illustrate what the entity functions may be regardless of the determination for registration (and the ensuing obligation to NERC Reliability Standards construct if registered.)

ROP definition in Appendix 5b: “Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.”

ROP definition in Appendix 2:” “Distribution Provider” means the entity that provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**”

Glossary of Terms Definition: “Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."

Likes 0	
Dislikes 0	

Response

Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller

Answer	
Document Name	

Comment

Black Hills Corporation agrees with other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	
Comment	

Black Hills Corporation agrees with other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.

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 other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1

Answer	
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Exelon suggests the drafting team consider allowing TP/PCs to establish a threshold for aggregate DER reporting. Certain types of DERs such as non-exporting, or DERs connected behind the meter as load offsetting DERs may not be of concern to the TP/PC should be exempt from DP/TO data collection and reporting requirements. Data collection and reporting requirements should focus on "front of meter" connected DERs who primarily export energy, or DERs participating in wholesale markets.

Additionally, FERC Order 2222 will require some level of DER data reporting and modeling that may result in the proposed changes to MOD-032 becoming duplicative of, and in some cases in conflict with, obligations imposed by Order 2222.

Likes 0	

Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Transmission Owners who are not Distribution Providers likely have no knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. Transmission Owner visibility for load demand is typically limited to historical telemetered MW and MVAR data. This finding, especially with regards to DERs, has already been well-documented. A key recommendation in the NERC Reliability and Security Technical Committee (RSTC) subcommittee approved the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was:

"TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements or practices that will ensure this data is available. ***As the TPs, PCs, and TOs are dependent on the DP to have the data made available****, this will likely require actions from state regulatory bodies and DPs to establish requirements to gather this information" (page 7 of 61).*

The SDT should consider that Transmission Owners should not be held accountable for demand and DER data that they have no cognizance of. Additionally, the SDT should remember that most DER are smaller than the BES resource threshold or reside on a distribution system. The threshold for an entity to be registered as a Distribution Provider is 75 MW of load. This implies that the majority of DERs are and will be connected to systems outside the scope and visibility of Transmission Owners, as well as existing Distribution Providers. To emphasize this reality: as of 15 May 2023, there were 314 Distribution Providers registered with NERC (excluding UFLS-only DPs). Of those DPs, 96 were not otherwise registered as either a PC, TP, or TO. While it may be misunderstood that only 96 DPs may become newly applicable and participatory in model data collection given the draft changes to MOD-032-2, this ignores that the latest EIA 861 data (collected in 2021; published in 2022) reflects about 1,190 distribution utilities reflecting almost 197,000 distribution circuits in the continental US. In other words, it may be reasonable to conclude that 74% of the distribution utilities in the US do not meet the NERC registration threshold. Furthermore, PCs, TPs, and TOs have no regulatory relationship with these unregistered entities and cannot be held responsible for DER data for which that are not aware.

In June 2022, NERC published its "Inverter-Based Resource Strategy" that recognized efforts necessary to analyze the breakdown of resource size, location, type, and applicability with the BES definition to make a determination of whether the current BES threshold should be updated to reflect the changing resource mix" (page 9 of 10). Subsequently, the NERC Member Representatives Committee (MRC) and Board of Trustees (BOT) technical session on inverter-based resources in February 2023 emphasized the need for a focus on functional registration noting: "industry is increasingly challenged with addressing reliability issues for unregistered inverter-based resources, and those resources are reaching critical mass in some parts of the country. The lack of requirements currently imposed on those resources creates local and regional reliability risks to the BPS in aggregate. This issue compounds in many areas with the growing presence of distributed energy resources (DERs) connected to the distribution system." In response to the FERC directive "Registration of Inverter-based Resources", NERC filed a proposal to modify its Rules of Procedure to "include a new function comprised of owners of IBRs interconnected to the BPS." The Generator Owner – Inverter-Based Resource (GO-IBR) registration would include "owners of IBRs which have aggregate nameplate capacity of less than or equal to 75 MVA and greater than or equal to 20 MVA interconnected at a voltage greater than or equal to 100 kV; or Owners of IBRs which have aggregate nameplate capacity of greater than or equal to 20 MVA interconnected at a voltage less than 100 kV."

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	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF suggests that NERC consider the work being performed under Project 2023-05 to revise FAC-001 – Facility Interconnection Requirements to include Distribution Provider which may help to alleviate the drafting team's concerns regarding the ability of either TO or DP needing to obtain data from unregistered entities that own DERs.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
Attachment 1 Data Reporting table (Steady State Column items 2, and 9, and Dynamics Column items 5, and 10) has added language indicating that the Transmission Owner (TO) is the responsible entity for submitting modeling data when a demand is not associated with a registered Distribution Provider. AZPS requests clarification regarding the type of entity that would have load, but not be a registered distribution provider. AZPS is concerned that the Transmission Owner may not have the ability to produce or acquire certain load information from an unregistered entity unless there is some other type of contractual relationship in place.	
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	
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) and MRO NSRF for question #6.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
In Attachment 1, Item 9, Texas RE recommends the SDT consider not removing the minimum and maximum for Real Power capability and Reactive Power capability (minimum and maximum) for DER data requirements. If the minimum and maximum Real Power and Reactive Power data is available, it should be submitted the TP/PC to be included in the system model which will yield more accurate models that are represented in Real-Time operations.	
Likes 0	
Dislikes 0	
Response	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	

Very little has changed from Draft 1 to Draft 2 of the proposed modifications to MOD-032-2. ATC supports the comments from the MRO-NSRF.

In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry consideration. A separate effort should be initiated to explore making DER entities above a specified threshold a NERC registered entity to ensure data will be correctly shared.

The SDT may also consider waiting until possible modifications have been suggested to MOD-032 in response to FERC Order 901 and IBR modeling.

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	

While these modifications are necessary, approving them prior to the SDT's documented concerns over the changes to the DP registration creates a disconnect that has the potential for unintended future consequences. SRP recommend the SDT crate a SAR for adjusting the definition of DP to include the DER resources prior to moving forward with this effort.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	
Document Name	
Comment	

SPP recommends this drafting team coordinates with the Project 2023-08 drafting team to ensure the appropriate DER data is identified as well as listed to meet the needs of the two standards from an efficient and reliability prospective.

Furthermore, we recommend that the drafting team consider creating an independent registration for the TO with direct connection to DERs (R-DERs). From our perspective, the proposed Attachment 1 (footnotes) does not clearly define the role for this particular Transmission Owner (TO). Moreover, the independent document can be used to provide clarity on the expectation of the role for the TO with direct connection to DERs (R-DERs).

In support of the proposed solution, we recommend that the drafting team review the efforts made in the NERC Rules of Procedures (RoP) in reference to the GO (IBR) and GOP (IBR) pertaining to their definition and registration.

Additionally, we recommend that the drafting team takes into consideration the impact of creating a separate project to address the proposed definition in an independent process.

We have the concern that the creation of an independent project for the definition will only delay the efforts of addressing the needs for DER data collection. From our perspective, the definition effort needs to be finalized before pursuing other activities associate with data collection.

Finally, SPP recognizes that DPs and TOs have expressed concern with their ability to obtain granular DER data and because of this, the proposed data collection modifications to MOD-032-2 may not be accepted by industry. To help reach consensus, SPP suggests that the drafting team consider an alternative mechanism that would allow the DPs and TOs to forecast DER data based on their knowledge of DER penetration on their systems, especially when the data is not directly available through a NERC standard.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute for Duke Energy’s official response.

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	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
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	
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 respectfully abstains from this ballot event and recommends NERC staff, the Standards Committee, and the Standards Drafting Team revisit the project scope in light of the directives in FERC Order 901, issued October 19th, 2023.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

AES Clean Energy believes that the new requirements for DERs will help TPs and PCs to better understand the root cause of system instability. However, there is still concern about the ability of the TO and DP to obtain the data from unregistered entities that own the DERs. Currently, FAC-001 allows the TO to specify its interconnection requirements which may help TO to obtain the necessary data. However, there is no similar requirement for DP. AES Clean Energy recommends the Standard Drafting Team to look into this as well.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	
Document Name	

Comment

Eversource recommends either Footnote 5 or the requirements be modified to make clear that the next closest DP or TO to an unregistered distribution provider should not be held responsible for providing DER data in case the unregistered entity does not supply this information, but only responsible to request this data. If the unregistered distribution provider does not supply this information, the DP or TO should remain compliant as long as they submitted the request.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	
Document Name	

Comment

Buckeye Power, Inc. supports the comments of ACES:

We have a great deal of apprehension as it relates to proposed language in Footnote 5 of Attachment 1. Footnote 5 states (emphasis added):
"Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column."
By what method should it be determined which registered entity is the "next closest electrically connected". Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the "next closest electrically connected" and how? In order to make this determination, a certain amount of knowledge about the other entity's infrastructure is required.
Of even greater concern is the continued inclusion of data from unregistered entities despite the open acknowledgment by the SDT of the challenges with collecting said data (see Technical Rationale, paragraph 2). We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved and can be included in the next draft of MOD-032-2.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

Transmission Owner is not listed as a Functional Entity to which the proposed standard(s) should apply in the SAR. The SAR states that the Functional Entities to which the proposed standard(s) should apply are the Transmission Planner (TP), the Planning Coordinator (PC) and the Distribution Provider (DP). This section of the SAR is designed to, "assist the NERC Standards Committee in appointing a drafting team with the appropriate members." The proposed language in ATTACHMENT 1, affects and changes the obligations of the Transmission Owner (TO). Changes to the obligations of the Transmission Owner (TO) were not approved in the SAR and SDT members selected may not provide adequate representation of TOs.

In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry consideration. NV ENERGY recommends that the Standard Drafting Team consider utilizing the procedures allowed for by NERC Rules of Procedure to halt activity on this project until such time that issues surrounding data collection from entities who have no obligation to comply are addressed.

NV Energy has concerns with Footnote 5 of Attachment 1:

“Where DER is connected to an unregistered Distribution Provider, the **next closest electrically connected** registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the “dynamics” column.”	
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	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
There needs to be a way to exempt or use generic models for legacy systems. Additionally, with some state regulators, such as the MPSC, it may be difficult to request information from customers that are not within the MPSC procedures and rules.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	

Comment
- Currently, the existing U-DERs are not obligated to provide any data for models. It may not be a problem for new U-DERs since data requirement can be incorporated in the IOA. - It is more appropriate to list the item 9.d in steady-state modelling requirement under dynamic modelling data requirements. (d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.)

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment
Transcription Owner is not listed as a Functional Entity to which the proposed standard(s) should apply in the SAR. The SAR states that the Functional Entities to which the proposed standard(s) should apply are the Transmission Planner (TP), the Planning Coordinator (PC) and the Distribution Provider (DP). This section of the SAR is designed to, “assist the NERC Standards Committee in appointing a drafting team with the appropriate members.” The proposed language in ATTACHMENT 1, affects and changes the obligations of the Transmission Owner (TO). Changes to the obligations of the Transmission Owner (TO) were not approved in the SAR and SDT members selected may not provide adequate representation of TOs. In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry consideration. MRO NSRF recommends that the Standard Drafting Team consider utilizing the procedures allowed for by NERC Rules of Procedure to halt activity on this project until such time that issues surrounding data collection from entities who have no obligation to comply are addressed. The NSRF has concerns with Footnote 5 of Attachment 1: “Where DER is connected to an unregistered Distribution Provider, the **next closest electrically connected** registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the “dynamics” column.” By what method should it be determined which registered entity is the “next closest electrically connected?” Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the “next closest electrically connected” and how? In order to make this determination, a certain amount of knowledge about the other entity’s infrastructure is required.

In closing, the NSRF would like to reemphasize the significant challenges in collecting the data in question from non-NERC-registered entities, challenges that the SDT itself has acknowledged (see Technical Rationale, paragraph 2).We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
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 of both EEI and the MRO NSRF.	
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
Industry might be more open to language that mimics FERC Order 901, Paragraph 141, for Verification of IBR Plant Dynamic Model Performance. The requirements could be modified to allow the Transmission Owner and/or Distribution Providers, if unable to gather accurate DER data, or unable to gather DER data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of individual DERs and DERs in the aggregate using ***estimated data***. This would give the Planning Coordinators the latitude to use their best judgement and experience in developing the most accurate models for their areas if they cannot get the data from the DER owners or "unregistered Distribution Providers".

Likes 0	
Dislikes 0	

Response

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	

Comment
No TPL questions?

Likes 0	
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	
Document Name	

Comment
In Attachment 1, the steady state section 2 removed the TO due to the DP NERC glossary definition. I think the TO should also be removed from steady state section 9 and dynamics section 10 for the same reason.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	

Document Name	
Comment	
FirstEnergy believes Footnote 5 should be deleted. The next closest DP or TO to an unregistered distribution provider should not be held responsible for providing DER data outside of their control or ability to collect. Further, FirstEnergy supports EEI's comments which state: EEI notes that this project has been listed as a low priority project. While we understand this may have some immediate impacts on the work being conducted by this SDT, we suggest that a two phased approach for the revision of MOD-032 might address the immediate concerns surrounding efforts to align registration under Project 2017-02. Phase 1: Consider completing the work from project 2017-02 Standards Alignment with Registration: Replace Load-Serving Entity (LSE) with Distribution Provider (DP), remove the Planning Authority (PA) functional entity name and keep the Planning Coordinator (PC) functional entity name, and make the associated LSE / DP functional changes to the standard requirements. Phase 2: Please consider addressing additional DER data requirements, after further discussion regarding how GO-IBR and GOP-IBR standards are going to be addressed and what is needed from Distribution Providers regarding unregistered IBRs.	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 2 - MOD-032-2
Comment Period Start Date:	10/6/2023
Comment Period End Date:	11/20/2023
Associated Ballot(s):	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan AB 2 OT 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 AB 2 ST 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 AB 2 NB

There were 71 sets of responses, including comments from approximately 185 different people from approximately 114 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. **Given the explanation in the Technical Rationale and response to industry comment, do you agree with the proposed definition for DER?**

2. **Are there any other clarifications needed in the Technical Rationale?**

3. **Do you agree the modifications made in MOD-032-2 will improve system modeling and reliability?**

4. **Do you agree the modifications made in MOD-032-2 are cost effective?**

5. **Do you agree with the Implementation Plan for revised MOD-032-2?**

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
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
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

Jaimin Patal	Saskatchewan Power Corporation (SPC)	1	MRO
Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
Marc Gomez	Southwestern Power Administration (SWPA)	1	MRO
Fred Meyer	Algonquin Power Co.	3	MRO
George Brown	Pattern Operators LP	5	MRO
Larry Heckert	Alliant Energy (ALTE)	4	MRO
Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
Bryan Sherrow	Board Of Public Utilities (BPU)	1	MRO
Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
Bobbi Welch	Midcontinent ISO, Inc.	2	MRO

					Michael Ayotte	ITC Holdings	1	MRO
Public Utility District No. 1 of Chelan County	Anne Kronshage	6		Public Utility District No. 1 of Chelan County - Voting Group	Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	Ali Miremadi	CAISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					John Pearson	ISO New England, Inc.	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC

					Elizabeth Davis	PJM	2	RF
					Charles Yeung	SPP	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
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
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Andy Fuhrman	Minnkota Power Cooperative, Inc.	1	MRO
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC

Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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
Southern Company - Southern Company Services, Inc.	Pamela Frazier	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

					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	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
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
Scott Brame	Scott Brame		SERC	NCEMC	Richard McCall	North Carolina Electric Membership Corporation	4	SERC
					Reid Cashion	North Carolina Electric Membership Corporation	5	SERC
					Chris Dimisa	North Carolina Electric Membership Corporation	3	SERC
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
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Sheri Maxey	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Mason Favazza	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc.	2	MRO
					Dee Edmondson	Southwest Power Pool Inc.	2	MRO
					Jim Williams	Southwest Power Pool Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool, Inc. (RTO)	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
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
					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

1. Given the explanation in the Technical Rationale and response to industry comment, do you agree with the proposed definition for DER?	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI's comments which state: we do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition. We additionally do not agree or support the notion that from a NERC Reliability Standard compliance standpoint, entities should be held accountable for DERs that fall outside of the NERC registration criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
We do not agree with the proposed definition for DER, nor do we agree that the definition for the term DER should be defined by the drafting team of single project working within the confines of that project as set forth by the Standard Drafting Process. We are concerned with the proliferation of NERC projects that are either directly, or indirectly, related to DERs and the potential consequences of the proposed DER definition. A definition that impacts multiple standards should be developed outside the scope of any individual standard and consider the impact to all of the affected NERC Reliability standards. We have for example a GO/GOP-registered plant that feeds a DP-registered data center in behind-the-meter fashion, i.e. upstream of the POI to the TO. This 2.5 GW generation facility is clearly not a Distributed Energy Resource, yet it seems to be included under the currently proposed DER definition, depending on how one interprets the term, “parallel operation.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition. Re: example Such installations would require GO registration and information should already be provided by the registered GO. However, the DT understands that there could be a need to coordinate with the PC/TP so as to not double count the capacity.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	

Answer	No
Document Name	
Comment	
WEC Energy Group does not agree with the proposed definition for DER for the reasons stated by both EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to EEI and MRO NSRF.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports the MRO NSRF Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to MRO NSRF.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

MRO NSRF does not agree with the proposed definition for DER; further, the MRO NSRF does not believe that the definition for the term DER should be defined solely by this Standard Drafting Team within the parameters of Project 2022-02. With the proliferation of NERC projects that are either directly, or indirectly, related to DERs, MRO NSRF contends that a definition, for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed in a separate project.

Additionally, MRO NSRF has concerns that the proposed definition for DER may fall outside the purview of NERC Reliability Standards as allowed for by Section 215(a)(1) of the Federal Power Act ("The term [bulk-power system] does not include facilities used in the local distribution of electric energy.").

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Thank you for your comments.
1A: DT should not define DER - separate project needed
The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition.

1B: Definition falls outside NERC jurisdiction
Defining terms is not bound/restricted to NERC jurisdictional authority. The NERC glossary includes many examples of such defined terms including, but not limited to: Demand, Fault, Hourly Value, Interpersonal Communication, Load, and Vegetation.

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Entergy agree with NAGF comments. The NAGF does not agree with the proposed definition for DER, nor do we agree that the definition for the term DER should be defined by the drafting team of single project working within the confines of that project as set forth by the Standard

Drafting Process. The NAGF is concerned with the proliferation of NERC projects that are either directly, or indirectly, related to DERs and the potential consequences of the proposed DER definition. A definition that impacts multiple standards should be developed outside the scope of any individual standard and consider the impact to all of the affected NERC Reliability standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
- MH recommends using “Bulk Power System” instead of “Bulk Electric System" - It is essential to explicitly state both exporting Real Power to the BPS and offsetting Real Power load. Proposed Definition: Generators and energy storage technologies connected to the Distribution Provider’s system that are capable of exporting Real Power or offsetting Real Power load in non-isolated parallel operation with the Bulk Power System.	
Likes 0	

Dislikes 0	

Response

Thank you for your comments.
Facilities operating in non-isolated parallel operation with the BPS are generally also operating in non-isolated parallel operation with the BES and vice versa, so to a certain extent it does not really matter which term is used in the definition. The DT chose to use “Bulk Electric System” in the proposed definition to align with the concept that NERC reliability standards are generally intended to ensure the reliability of the BES.

The proposal to explicitly refer to both exporting Real Power and offsetting Real Power Load in the DER definition is addressed in the Technical Rationale. The DT consensus was that explicitly using the term “offsetting” in the definition could be interpreted in unintended ways.

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

Having two different defintions for Distribution Provider makes the scope confusing. The definition is too broad and we believe that there needs to be threshold for what constitutes a DER.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
1C: Definition needs threshold/too broad/creates compliance obstacle
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

1G: Confusion between glossary DP and registered DP The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
There needs further clarification if the DER is going to include every DER or there will be a threshold as there are several small projects that would be extremely costly to have to abide by each NERC mandated modeling and testing requirement when their impact to the BES is marginal. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Neither the proposed definition, nor MOD-032-2 mandate any testing related to DER. The DT proposals do not require detailed models for every individual DER. The DT contends that DPs should already have a record and basic understanding of DER that is connected to their system (e.g. rooftop solar, batteries, etc.) similar to how they have a record and basic understanding of houses, factories, and commercial spaces connected to their system. Such information should be sufficient for PCs and TPs to properly represent potential DER reliability impacts.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) does not support the development of an additional NERC Reliability Standard to define DER. CEHE finds the proposed revisions to MOD-032-2, too prescriptive and recommends that data reporting requirements for DERs listed in Attachment 1 be determined by the Planning Coordinator, in coordination with the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition. As stated in the Technical Rationale, the STD contends that, “Specific data items listed for DER reflect the minimum amount of information expected to be needed to reasonably represent DER in transmission system models.”	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV ENERGY does not agree with the proposed definition for DER; further, NV Energy does not believe that the definition for the term DER should be defined solely by this Standard Drafting Team within the parameters of Project 2022-02. With the proliferation of NERC projects	

that are either directly, or indirectly, related to DERs, NV ENERGY contends that a definition, for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed in a separate project. Additionally, NV ENERGY has concerns that the proposed definition for DER may fall outside the purview of NERC Reliability Standards as allowed for by Section 215(a)(1) of the Federal Power Act ("The term [bulk-power system] does not include facilities used in the local distribution of electric energy.").	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition. 1B: Definition falls outside NERC jurisdiction Defining terms is not bound/restricted to NERC jurisdictional authority. The NERC glossary includes many examples of such defined terms including, but not limited to: Demand, Fault, Hourly Value, Interpersonal Communication, Load, and Vegetation.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES:	

We at ACES applaud the attempt made by the SDT to clearly define what is by nature a nebulous concept; however, we feel that the current definition is overly broad and will create an insurmountable compliance obstacle.

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may not have a material impact to the reliability of the BES.

Additionally, there is a seemingly interchangeable use of the terms Distributed Energy Resource (DER) and Inverter Based Resource (IBR) to describe the same types of assets. It is our opinion that a singular definition should be developed to define these resource types. Given the currently proposed changes to the NERC Rules of Procedure (specifically Appendices 5A and 5B), we believe that the term IBR should be utilized in lieu of DER. Moreover, it is our opinion that the newly proposed GO-IBR and GOP-IBR registrations should be utilized when developing MOD-032-2. In short, we believe that the NERC registration criteria are well reasoned and were intentionally developed to only include those entities and/or resources that could have a material impact to the BES.

In conclusion, it is our recommendation that the proposed MOD-032-2 Reliability Standard be modified to include a non-zero MVA threshold. We believe that the DP should only be required to collect data from NERC registered entities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
1C: Definition needs threshold/too broad/creates compliance obstacle
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable. 1D: IBR/DER - single definition/GO-IBR The scope of the SAR was to address DER. Not all DER is IBR and not all IBR is DER. The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e. greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES Clean Energy appreciates the Standard Drafting Team's research into the various DER definitions adopted across the industry and regions. However, with the introduction of a new definition from NERC, this will create additional confusion for entities, especially those that operate in regions where the term DER is currently utilized. AES Clean Energy recommends that the Standard Drafting Team take an approach of proposing a broader definition of DER that is not specific to MOD-032 and will be applicable to other on-going DER related standard projects before moving forward with MOD-032 changes. This is similar to that of Project 2020-06 where definitions of IBRs were proposed for industry feedback.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1E: Need broader definition for DER not specific to MOD-032	

The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032.	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	No
Document Name	
Comment	

- Oncor Electric Delivery Company LLC ("Oncor") considers the DER definition used in the Technical Rationale for Reliability Standard MOD-032-2 too vague because it does not contain a voltage class threshold for an energy resource to be considered a DER.
- Oncor's view of DER is consistent with ERCOT's definition of DER, which is: "An electrical generating facility consisting of one or more on-site distributed generation units connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system." This definition can be found here: https://www.ercot.com/files/docs/2017/03/24/DER_OnePager_FINAL.pdf
- From Oncor's experience, the total capacity of the installation's on-site distributed generation units may exceed ten megawatts (MW); however, no more than ten MW of the installation's capacity will be allowed to export into the grid at any point in time at the point of common coupling.
- Is there any MW size threshold for Generator and energy storage technologies to be taken into account when the end-use customer is served at transmission voltage? We would prefer a MW size threshold be specified in the definition.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
1F: Include voltage class in definition
DT views that it is not appropriate to include voltage level in the DER definition given the different considerations of voltage level across the continent. As noted in the NERC glossary definition, the Distribution Provider "is not defined by a specific voltage, but rather as performing the distribution function at any voltage."

1C: Definition needs threshold/too broad/creates compliance obstacle

The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
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	
Thank you for your comments. See response to EEI.	
David Rivera - New York Power Authority - 3	
Answer	No
Document Name	
Comment	
*NYPA appreciates the standard drafting team's effort to define '**DER**' and aligning it with IEEE 1547, but we believe a more detailed definition is essential for better interpretations. The current proposed definition seems too narrow, given the use of the term DER across multiple NERC standards. NYPA suggest SDT to propose a more detailed **DER** definition with examples to avoid potential misinterpretations as DER which is not solely for renewables.*	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. 1E: Need broader definition for DER not specific to MOD-032 The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The Technical Rationale includes examples of facilities intended to be in scope.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES and MRO NSRF.	
Bill Garvey - Dominion - Dominion Virginia Power - 3	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. See response to EEI.	
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	
Thank you for your comments. See response to MRO NSRF.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy's official response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP recommends that the drafting team creates propose language in the Technical Rationale that suggests including the prosed definition in the Rules of Procedure (RoP- Appendix 2A) to ensure proper alignment with the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The suggestion is beyond the scope of Project 2022-02. If DER was added to and used within the Rules of Procedure (ROP), it would be determined at that time if our proposed NERC glossary definition was appropriate (not all the definitions in ROP Appendix 2 are from NERC glossary).	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC agrees that there is a need for a NERC DER definition, but ATC does not support the SDT's proposed definition for DER. Defining DER within the confines of a single NERC project (i.e., NERC Project 2022-02) could limit the definition's use within other ongoing and future DER standard drafting efforts. With the number of NERC projects under modification and existing Standards that are either directly or indirectly related to DERs, ATC believes that a definition for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed outside the scope of any individual standard, and should consider the impact to any affected NERC Reliability standards.	

If the SDT does go forward with a NERC Glossary of Terms definition for DER, the NERC definition of DER should not involve itself in facilities that do not fall under the purview and regulation of NERC (e.g., local distribution facilities).

ATC believes that the text “Distribution Provider’s system” should not be referenced in the DER definition as it refers to the NERC glossary definition of Distribution Provider, not the NERC registered entity and in some cases this is different.

If the term “Distribution Provider” is used, ATC also suggests that there should be a clearer distinction between Distribution Provider as a NERC glossary term and Distribution Provider as a NERC registered entity.

As an alternative, the SDT could replace “connected to the DP’s system” with “not directly connected to a bulk power system.”

Additionally, ATC requests that the standard explicitly allows the PC to determine thresholds (ex: MW or MVA) for both the collection of DER data and for the modeling of DERs. Alternatively, thresholds for DER data collection and for DER data modeling could be included in the standard. Thresholds for DER data collection and for DER data modeling could also be included in the DER definition but this may be less appropriate/ flexible for future use.

DER thresholds greater than zero MW are needed to manage the potentially large administrative burden on NERC Registered Entities such as the TOs, TPs, and DPs.

ATC encourages a new NERC Registered Entity for DER (ex: DP-DER or IBR-DER) to bring DER data reporting accountability to those unregistered DPs with DER.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
1A: DT should not define DER - separate project needed
The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this.

1B: Definition falls outside NERC jurisdiction

Defining terms is not bound/restricted to NERC jurisdictional authority. The NERC glossary includes many examples of such defined terms including, but not limited to: Demand, Fault, Hourly Value, Interpersonal Communication, Load, and Vegetation.

1G: Confusion between glossary DP and registered DP
The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.

1C: Definition needs threshold/too broad/creates compliance obstacle
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

As noted in the Technical Rationale, developing new registration criteria is beyond the scope of this project.

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), NAGF and MRO NSRF for question #1.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. See responses to EEI, NAGF, and MRO NSRF.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
There needs further clarification if the DER is going to include every DER or there will be a threshold as there are several small projects that would be extremely costly to have to abide by each NERC mandated modeling and testing requirement when their impact to the BES is marginal. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Neither the proposed definition, nor MOD-032-2 mandate any testing related to DER. The DT proposals do not require detailed models for every individual DER. The DT contends that DPs should already have a record and basic understanding of DER that is connected to their system (e.g., rooftop solar, batteries, etc.) similar to how they have a record and basic understanding of houses, factories, and commercial spaces connected to their system. Such information should be sufficient for PCs and TPs to properly represent potential DER reliability impacts.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF does not agree with the proposed definition for DER, nor do we agree that the definition for the term DER should be defined by the drafting team of single project working within the confines of that project as set forth by the Standard Drafting Process. The NAGF is	

concerned with the proliferation of NERC projects that are either directly, or indirectly, related to DERs and the potential consequences of the proposed DER definition. A definition that impacts multiple standards should be developed outside the scope of any individual standard and consider the impact to all of the affected NERC Reliability standards. *In addition, the NAGF is concerned with the inconsistency of DER term used across the industry as stated in the examples provided in the Technical Rationale. Regions or even states have their own definition of DERs which may impact a Generator Owner's ability to comply with both NERC and other state or regional requirements. It is recommended that NERC perform outreach to regions and/or states to try to ensure some consistency on how the term is going to be used.*

Likes 0	
Dislikes 0	

Response
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition.

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	

Comment
The definition for the term DER should be defined solely by this Standard Drafting Team within the parameters of Project 2022-02. With the proliferation of NERC projects that are either directly, or indirectly, related to DERs. A definition, for a term such as DER, which is a broadly utilized term that impacts multiple standards, should be developed in a separate project. Additionally, the proposed definition for DER may fall outside the purview of NERC Reliability Standards as allowed for by Section 215(a)(1) of the Federal Power Act ("The term [bulk-power system] does not include facilities used in the local distribution of electric energy.").

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition. 1B: Definition falls outside NERC jurisdiction Defining terms is not bound/restricted to NERC jurisdictional authority. The NERC glossary includes many examples of such defined terms including, but not limited to: Demand, Fault, Hourly Value, Interpersonal Communication, Load, and Vegetation.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	

Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEi comments. The current proposed definition appears to conflict with how FERC has previously defined DER: “any resource located on the distribution system, any subsystem thereof or behind a customer meter”, which may include, but not limited to, “electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI. The Technical Rationale already provides a description for why the FERC definition is not suitable for application within the context of reliability standards.	

Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	
Comment	
NCEMC supports comment of ACES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to ACES.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No

Document Name	
Comment	
Black Hills Corporation does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition.	
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 does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR, which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR, which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition.	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	

Black Hills Corporation does not support the development of a DER definition within the NERC Reliability Standards Project 2022-02 Modifications to TPL-001 and MOD-032. Black Hills Corporation agrees with EEI and NAGF comments that the inclusion of the proposed DER definition will affect multiple other NERC standards and as such a DER definition should be defined outside the scope of a single standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR, which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment
As stated in our draft 1 comments, EEI does not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition. We additionally do not agree or support the notion that from a NERC Reliability Standard compliance standpoint, entities should be held accountable for DERs that fall outside of the NERC registration criteria.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. 1A: DT should not define DER - separate project needed The SC approved the DT and the SAR, which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

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 applaud the attempt made by the SDT to clearly define what is by nature a nebulous concept; however, we feel that the current definition is overly broad and will create an insurmountable compliance obstacle.

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may not have a material impact to the reliability of the BES.

Additionally, there is a seemingly interchangeable use of the terms Distributed Energy Resource (DER) and Inverter Based Resource (IBR) to describe the same types of assets. It is our opinion that a singular definition should be developed to define these resource types. Given the currently proposed changes to the NERC Rules of Procedure (specifically Appendices 5A and 5B), we believe that the term IBR should be utilized in lieu of DER. Moreover, it is our opinion that the newly proposed GO-IBR and GOP-IBR registrations should be utilized when developing MOD-032-2. In short, we believe that the NERC registration criteria are well reasoned and were intentionally developed to only include those entities and/or resources that could have a material impact to the BES.

In conclusion, it is our recommendation that the proposed MOD-032-2 Reliability Standard be modified to include a non-zero MVA threshold. We believe that the DP should only be required to collect data from NERC registered entities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
1C: Definition needs threshold/too broad/creates compliance obstacle
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

1D: IBR/DER - single definition/GO-IBR

The scope of the SAR was to address DER. Not all DER is IBR and not all IBR is DER. The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: We at ACES applaud the attempt made by the SDT to clearly define what is by nature a nebulous concept; however, we feel that the current definition is overly broad and will create an insurmountable compliance obstacle. We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may not have a material impact to the reliability of the BES. Additionally, there is a seemingly interchangeable use of the terms Distributed Energy Resource (DER) and Inverter Based Resource (IBR) to describe the same types of assets. It is our opinion that a singular definition should be developed to define these resource types. Given the	

currently proposed changes to the NERC Rules of Procedure (specifically Appendices 5A and 5B), we believe that the term IBR should be utilized in lieu of DER. Moreover, it is our opinion that the newly proposed GO-IBR and GOP-IBR registrations should be utilized when developing MOD-032-2. In short, we believe that the NERC registration criteria are well reasoned and were intentionally developed to only include those entities and/or resources that could have a material impact to the BES.

In conclusion, it is our recommendation that the proposed MOD-032-2 Reliability Standard be modified to include a non-zero MVA threshold. We believe that the DP should only be required to collect data from NERC registered entities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
1C: Definition needs threshold/too broad/creates compliance obstacle
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

1D: IBR/DER - single definition/GO-IBR
The scope of the SAR was to address DER. Not all DER is IBR and not all IBR is DER. The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity

The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The drafting team should consider defining “Transmission connected DERs” (100 kV and above) and “Distribution connected DERs” (below 100 kV). The proposed DER definition begins with “generators and energy storage technologies…”, implying that a Generator Owner is involved. The NERC Glossary of Terms defines a Generator Owner as the “Entity that owns and maintains generating Facility(ies)”. Would it be more practical to acquire DER data from the associated GO rather than the DP/TO; particularly in instances where the GO is a NERC registered entity?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1F: Include voltage class in definition DT views that it is not appropriate to include voltage level in the DER definition given the different considerations of voltage level across the continent. As noted in the NERC glossary definition, the Distribution Provider “is not defined by a specific voltage, but rather as performing the distribution function at any voltage.” In most cases, the GO for DER is not a NERC-registered entity. It does not seem practical to create a NERC registration for DER GO because it would need to extend down to the level of residential solar (which in aggregate can significantly impact BPS reliability). Thus, it seems most appropriate for DPs, which would seem to have a need to know about and understand the capabilities of such DER installations to ensure reliable distribution system operations, to report DER data.	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them. Also, It should say BES in front of "Generators" and before "energy storage technologies".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES, EEI, MRO, NAGF, and Talen. The DT is not proposing DER to be included in the BES, so the proposed modification to the DER definition was not made.	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Hi, please reference comments by Marty Hostler, NCPA Compliance Manager. Thank you, **Jeremy Lawson, P.E.**	

Generation Services Director of Engineering Northern California Power Agency	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to comments by Marty Hostler, NCPA Compliance Manager.	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with the definition of DER. Texas RE noticed a potential contradiction within the technical rationale and would like it clarified. On page 2 of the technical rationale, it states “It should be clear that MOD-032 2 applicability and compliance obligations refer to	

NERC registered DPs; the use of the DP term in the DER definition does not in itself imply any compliance." This seems to be contradicted on page 3, where it states: "The NERC glossary definition for DP1 notes that the DP is defined by providing the distribution function (this includes entities that may not be NERC-registered DPs)."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Compliance obligations are only established for NERC-registered entities in standards, not definitions. A DER is a DER whether it is connected to the system of a registered entity or not (i.e., the DER definition should not be dependent on entity registration). 1G: Confusion between glossary DP and registered DP The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The number of different DER definitions is confusing and difficult to work with. We agree with the proposed definition but it doesn't appear to be used consistently throughout the standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Attachment 1 was updated to add “aggregate” DER data. The DT believes this may address the concern.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
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.	
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.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
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.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
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.	
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.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, 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	
Thank you for your support.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
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.	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
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.	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
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	
Document Name	
Comment	
RF recommends revising the proposed definition to explicitly include behind the meter resources: "Generators and energy storage technologies connected to the Distribution Provider's system*, either directly or behind the meter of an end use customer,* that are capable of providing Real Power in non-isolated parallel operation with the Bulk Electric System."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT has avoided the use of the term "directly connected" as described in the Technical Rationale. However, an explicit reference to behind the meter resources was added to the proposed DER definition.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	

Document Name	
Comment	
The apparent use of a defined term for a registered entity (functional entity) may cause confusion in the industry. WECC appreciates the idea of trying to illustrate what the entity functions may be regardless of the determination for registration	
Likes 0	
Dislikes 0	
Response	
1G: Confusion between glossary DP and registered DP Thank you for your comments. The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.	

2. Are there any other clarifications needed in the Technical Rationale?	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Hi, please reference comments by Marty Hostler, NCPA Compliance Manager. Thank you, **Jeremy Lawson, P.E.** Generation Services Director of Engineering Northern California Power Agency	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to comments by Marty Hostler, NCPA Compliance Manager.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC signed on to ACES comments: While we do not agree with some of the SDT's viewpoints about the level of DER data required, we do appreciate the high level of effort made by the SDT to develop the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to ACES.	
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	
While we do not agree with some of the DT's viewpoints about the level of DER data required, we do appreciate the high level of effort made by the SDT to develop the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While EEI finds the Technical Rationale to be clear, we have concerns with the following statements and positions contained in the Technical Rationale:

Page 1; Rationale for Applicability Section:

EEI does not agree that TOs (or registered DPs) should be required to coordinate with the owners of distribution facilities that do not have an associated NERC-registered DP to ensure the availability of necessary data, either through interconnection agreements or other binding contracts. TOs and DPs have no ability to control interconnection agreements on other entity's system or the ability to obtain data from non-registered entities or facilities used in the local distribution of electric energy.

EEI is also concerned that the SDT acknowledges that data collection for DERs connected to unregistered entities is a problem and suggests that NERC should expand DP registration criteria or develop a DER-only DP registration criteria to address this gap but still believes there is value in moving MOD-032-2 forward with requirements for TOs and DPs when those obligations are limited to assets owned by the TOs and DPs.

Page 4 – Rational for Modifications to Attachment 1

EEI does not support the scope of modifications to MOD-032, Attachment 1 which obligates TOs and DPs to collect DER data on all relevant DERs including utility scale facilities and smaller behind the meter facilities, which appears to include all residential DERs even though these resources are used for local distribution.

EEI does not agree with the SDT's position that the PC/TP should have the authority to specify DER data to whatever level it deems appropriate. (Ref. the explanation of Footnote 4 from Attachment 1 of MOD-032).

The following statement (in boldface) should be struck from the Technical Rationale because TOs and DPs should have no obligation to provide any data related to DERs participating within a DER Aggregation in the organized markets. While the SDT appears to believe that while the data should be provided by the DER Aggregator, they believe that TOs and DPs still have an obligation to provide this data if requested to do so by the PC/TP: **This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.**

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent. 2B: FN 4 - disagree with PC/TP authority Data collection requirements for DER in MOD-032 are focused on what is necessary for reliability and may differ from the data collected by a DER Aggregator to participate in a market.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC appreciates the effort of the Standard Drafting Team in developing the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy's official response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	

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	
Thank you for your comments. See response to MRO NSRF.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES and MRO NSRF.	
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	
Thank you for your comments. See response to EEI.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES: While we do not agree with some of the SDT's viewpoints about the level of DER data required, we do appreciate the high level of effort made by the SDT to develop the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to ACES.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	

Comment	
NA	
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 agrees with the concerns expressed by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy has concerns with the following statements and positions contained in the Technical Rationale:	

Page 1; Rationale for Applicability Section:

EEI does not agree that TOs (or registered DPs) should be required to coordinate with the owners of distribution facilities that do not have an associated NERC-registered DP to ensure the availability of necessary data, either through interconnection agreements or other binding contracts. Such a requirement makes no sense. TOs and DPs have no ability to control interconnection agreements on other entity's system or the ability to obtain data from non-registered entities.

EEI is also concerned that the SDT acknowledges that data collection for DERs connected to unregistered entities is a problem and suggests that NERC should expand DP registration criteria or develop a DER-only DP registration criteria to address this gap but still believes there is value in moving MOD-032-2 forward with regulator obligations on TOs and DPs when it is recognized their ability to collect certain data is not possible.

Page 4 – Rational for Modifications to Attachment 1

EEI does not support the scope of modifications to MOD-032, Attachment 1 which obligates TOs and DPs to collect DER data on all relevant DERs including utility scale facilities and smaller behind the meter facilities, which appears to include all residential DERs even though these resources are used for local distribution.

EEI does not agree with the SDT's position that the PC/TP should have the authority to specify DER data to whatever level it deems appropriate. (Ref. the explanation of Footnote 4 from Attachment 1 of MOD-032).

EEI believes that the following statement (underlined) should be struck from the Technical Rationale because TOs and DPs should have no obligation to provide any data related to DERs participating within a DER Aggregation in the organized markets. While the SDT appears to believe that while the data should be provided by the DER Aggregator, they believe that TOs and DPs still have an obligation to provide this data if requested to do so by the PC/TP: This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity.

The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent. 2B: FN 4 - disagree with PC/TP authority Data collection requirements for DER in MOD-032 are focused on what is necessary for reliability and may differ from the data collected by a DER Aggregator to participate in a market.	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
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	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
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; John Nierenberg, 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	
Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
David Rivera - New York Power Authority - 3	
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	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	No
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	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	

We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them.

Specifically, we disagree with the SDT stating in the standard footnote 5 on page 16, first sentence "Where DER is connected to an unregistered Distribution Provider". This makes it appear as though said entity should be registered. If they are not in the NERC registry then they are not a DP.

Consequently, it should say "Where a DER is connected to a non-Distribution Provider".

We also disagree with the SDT re: proposed standard footnote 5 on page 16, second sentence. "An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider". Our view is that this seems to imply that another

DP or TO can determine, or has the responsibility of determining, if an entity should be registered as a DP. That is NERC's or the Regional Entities' responsibility; registration determination is not a DP's or a TO's responsibility.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES, EEI, MRO, NAGF, and Talen. 1G: Confusion between glossary DP and registered DP The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
The technical rationale doesn’t provide guidance on determining which facilities connected to the DP’s system would be classified as DERs and which ones would not. The current definition would classify any generation connected to a registered DP as a DER.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. All generation connected to a DP’s system (whether the DP satisfies the NERC registration criteria or not) is considered DER. As noted in the Technical Rationale, the PC/TP may specify certain classifications of DER that do not need to be reported by the DP - such exclusions would be specified in the PC/TP data reporting procedures and requirements.	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
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	
Thank you for your comments. See responses to IRC SRC	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The SDT should give consideration to paragraph 105 of FERC Order No. 901 which states that if distribution providers are unable to gather adequate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation.	
Likes 0	

Dislikes 0	

Response

Thank you for your comments. 6B: FERC 901 reference to allow estimated data
Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale.

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2

Answer	Yes
Document Name	2022-02 Unofficial_Comment_Form_SRC_11-20-23_FINAL_as filed.docx

Comment

The **ISO/RTO Council Standards Review Committee (SRC)**[1] recommends that the Technical Rationale include an explanation of why the term reactive power capability (*see* Draft #1 of MOD-032-2, Attachment 1, steady-state item 9c) has been removed in favor of the language added in Draft #2 of MOD-032-2, Attachment 1, steady-state item 9d. Our understanding is the change was made to focus on broadening the language to better describe the data needed to model operating characteristics (including ride-through capability, voltage support, frequency control, etc.) instead of focusing on mere operating capabilities.

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO, MISO, NYISO, PJM, SPP and ISO-NE (except for the response to question 6). ERCOT supports the response to question 2 only.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
2C: elimination of reactive power
The DT removed the reactive power capability in response to previous industry comments. A DER's reactive power operating characteristics can depend on many factors aside from the maximum capability, including the mode of reactive power control. For instance, if the DER is in volt/var control mode, the distribution system loading, voltage regulation scheme, and impedance can all affect the DER's reactive power

output. The Attachment 1 information provides a minimum baseline for information. The PC/TP may request additional information to make assumptions about aggregate DER reactive power operating characteristics.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Does the term "interconnection-wide" need to be capitalized.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Interconnection is defined in the NERC glossary as: “A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.” The DT believes that the use of non-capitalized “interconnection-wide” within MOD-032-1 may have been intentional; no change made.	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	Yes
Document Name	
Comment	

Black Hills Corporation does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	

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 does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation does not support the included language that the "next closest electrically connected registered entity (DP or TO)" is responsible for coordinating DER data with unregistered DPs. Black Hills Corporation agrees with EEI and NAGF comments that TO, or nearest registered DP do not have the ability or authority to gather or request data from unregistered DP entities.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Please provide the reasoning for elimination of reactive power (see Draft #1 of MOD-032-2, Attachment 1, item 9c) in favor of the added language in Draft #2 of MOD-032-2, Attachment 1, item 9d.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2C: elimination of reactive power The DT removed the reactive power capability in response to previous industry comments. A DER's reactive power operating characteristics can depend on many factors aside from the maximum capability, including the mode of reactive power control. For instance, if the DER is in volt/var control mode, the distribution system loading, voltage regulation scheme, and impedance can all affect the DER's reactive power output. The Attachment 1 information provides a minimum baseline for information. The PC/TP may request additional information to make assumptions about aggregate DER reactive power operating characteristics.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

While we may disagree with some of the positions taken by the Standard Drafting Team, the NAGF appreciates the efforts the Standard Drafting Team put forth in developing the technical rationale.

In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry. The NAGF recommends that the Standard Drafting Team re-consider how to address the issues surrounding data collection from entities who have no obligation to comply.

The NAGF recommends that the statement "Distribution Provider refers to the NERC glossary definition, not the NERC registered entity," be revised to be: "The term Distribution Provider in the DER definition includes all parties cited in the NERC Glossary definition of a Distribution Provider, some of whom may be registered as TOs and not as DPs. References to Distribution Providers in the requirements of MOD-032 pertain however only to entities registered as DPs."

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

1G: Confusion between glossary DP and registered DP
The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.

Alison MacKellar - Constellation - 5

Answer	Yes

Document Name	
Comment	
Clarification is needed on size of DERs applicable. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2D: Define DER threshold to model (either aggregate or individual) The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Both the Technical Rationale & the Standard need to address the following issue: If the TO/DP is required to report data that the DER owner has no obligation to provide, how does the SDT propose to eliminate this compliance risk in the interim while a permanent solution is developed.?	
Likes 0	

Dislikes 0	

Response
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

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 NAGF for question #2.	
Likes 0	
Dislikes 0	

Response
Thank you for your comments. See responses to EEI and NAGF.

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	Yes
Document Name	
Comment	
• Getting the gross demand of a registered/unregistered DP's DER will require tracking and retention of their DER data for TO/TP. Managing this additional DER data will put an undue burden on TPs. We request that the DER be responsible for submitting data to the PC/TPs directly.	

• As requested by Oncor in the previous comment period, clarification is needed by SDT on how to represent a single location with multiple types of DER.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT contends that TOs and DPs have a reliability need to know what is being connected to their systems in terms of gross demand and DER and should have methods for managing this information. The intent of MOD-032 revisions is to ensure that DER data is available to PCs and TPs for inclusion in system studies. Details about how data is to be reported are specified by the PC/TP per Requirement R1. SPIDERWG has published numerous reliability guidelines and white papers related to representing DER: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf. The DT contends that it is not appropriate to mandate a specific DER representation in MOD-032.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Clarification is needed on size of DER's applicable. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2D: Define DER threshold to model (either aggregate or individual)	

The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Regarding non registered DPs, as stated in the technical rationale *"the SDT recommends that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would unnecessarily delay the implementation of DER data requirements. The SDT believes there is value in moving forward with MOD-032-2 as it does provide substantial improvement with respect to ensuring DER data is available for inclusion in PC and TP studies."* We do not agree that this would unnecessarily delay the implementation. We believe it is necessary to delay the implementation because of this. Please explain the justification for moving forward with this known ambiguity which will cause significant compliance risk and may not ultimately be feasible until the process to modify NERC registry criteria is completed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 6J: Don't move forward without addressing registration gap The DT believes that the data collection covered by the current registration available covers a significant portion of the DER data and provides a reliability benefit prior to efforts to close the registration gap and collect the remaining DER data.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	

Answer	Yes
Document Name	
Comment	

In the “Inclusion of Aggregate Demand Clarification” section, it is suggested a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. In an era of energy efficiency and significant load transformation, it is extremely difficult to differentiate DER additions vs. other factors contributing to changing feeder loads. This suggestion should be removed as it could lead to false DER aggregation assumptions.

Foot Note 5 is an attempt by NERC to force requirements onto unregistered entities via registered entities. This requirement places compliance risk on TO’s and DP’s to request data where there is no enforcement support. The comments also don’t explain what would happen if the unregistered DP doesn’t provide the requested data.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Reference to historical load levels was removed from that section of the Technical Rationale.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	
Comment	

The addition of the wording to support Footnote 2: "In situations where DER is not separately metered, a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. A consistent reduction in load on the feeder may be indicative of DER interconnections. "

This may serve the purpose of determining approximate aggregate demand under item # 2 in Attachment-1, column-1 (steady-state), but won't support item # 9 which requires generator type (solar, battery etc.) and DER capabilities.

The addition of footnote 5 seems to be confusing. This can be addressed in the joint PC/TP modeling data requirements and reporting procedures developed per R1 (after coordinating with applicable DPs/TOs).

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The identified language was removed from the technical rationale. It was originally intended as an example rather than a covering potential situation.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

The standard as written places an untenable compliance burden on NERC registered entities. The technical rationale notes the challenges in collecting DER data from unregistered DPs. It does not note or address in any way the challenges in collecting DER data from the unregistered DER owners connected to DPs. These unregistered DER owners have no obligation or requirement under NERC standards to provide data for

modeling. Requiring that DPs provide modeling data for equipment they do not own and have no means to acquire data on leaves them in a position where they fail to comply with the standard through no fault of their own and despite their best efforts.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Please see our response to Question #3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. See response to Question #3.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

While we may disagree with some of the positions taken by the Standard Drafting Team, the NAGF appreciates the efforts the Standard Drafting Team put forth in developing the technical rationale.

In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry. We recommend that the Standard Drafting Team re-consider how to address the issues surrounding data collection from entities who have no obligation to comply.

We also recommend that the statement “Distribution Provider refers to the NERC glossary definition, not the NERC registered entity,” be revised to be, “The term Distribution Provider in the DER definition includes all parties cited in the NERC Glossary definition of a Distribution Provider, some of whom may be registered as TOs and not as DPs. References to Distribution Providers in the requirements of MOD-032 pertain however only to entities registered as DPs.”

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

1G: Confusion between glossary DP and registered DP
The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.

Alison MacKellar - Constellation - 5

Answer	Yes

Document Name	
Comment	
The standard needs to specify the size of DER that is required to model	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2D: Define DER threshold to model (either aggregate or individual) The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
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	
Please see Texas RE's answer to #1.	
Likes 0	
Dislikes 0	

Response
Thank you for your comments. See response to Texas RE comment for #1.

3. Do you agree the modifications made in MOD-032-2 will improve system modeling and reliability?	
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 support the proposed changes to MOD-032-2 because many of the changes would obligate TOs and DPs to provide data that exceeds their ability to obtain. EEI further notes that during the Fall 2023 NPCC Compliance and Reliability Conference a presentation titled "Inverter Based Resource Work Plan" was given and appears to use data from a Berkeley National Laboratory Report. The presentation goes on to indicate that BES IBRs (75MW at ≥100kV) account for 84% and non-BES (≥20MW & ≤75MW at ≥100kV plus ≥MW at <100kV) account for an additional 14%; for a total of 98% of the IBRs currently interconnected on the grid. This data additionally indicates that small IBRs (<20MW at any kV) only account for 2% of the connected IBRs and if correct, would mean these resources would have no meaningful impact on the Reliability of the BPS. Moreover, in FERC Order No. 901 (Reliability Standards to Address Inverter-Based Resources), the Commission made it clear that the focus of changes to NERC Reliability Standards, as it relates to modeling of DERs, is to be limited data to aggregate data not granular details on a non-aggregated basis. Given the NPCC data and FERC Order No. 901, it would indicate that many of the proposed changes to MOD-032 are unnecessary for reliability. This would include modifications to MOD-032 that propose to provide PCs/TPs with the authority to request data that is overly granular and unnecessary to model the impacts of DERs on the BPS. IBRs that have a meaningful impact on the BPS should be registered. Once this has been done, PCs and TPs could seek the data they need directly from the registered resource, not the TOs or DPs that are unlikely to have the needed data. While we recognize the need to gather and model the impacts of DER resources on the distribution system, modeling should be limited to load demand and aggregate DER impacts/offsets. However, we do support obligating DER Aggregators who are participating in the organized markets to provide data on their aggregated resources to the PCs/TPs upon request. We do not support obligating TOs and DPs to gather non aggregated data, upon request.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. See response to EEI.	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Things appear to be specultive at this point.	
Likes 0	
Dislikes 0	
Response	
Thank you for your 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	
SMUD and BANC agree with the comments submitted by BC Hydro, especially pertaining to Footnote 5. We feel that the language in Footnote 5, and the Technical Rationale, do not support passing the compliance obligations of an “unregistered Distribution Provider” onto “the next electrically connected registered entity (DP or TO)”. If models are required for all DERs in the BPS, there is an increased chance of Planning Coordinators and Transmission Planners receiving inaccurate models (especially from “unregistered Distribution Providers”) as many Distribution Providers may not have the experience to model their DERs correctly which could pollute the base cases and diminish their quality.	

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

3B: Data accuracy
It is understood that modeling aggregate DER (based on collected data) will involve some assumptions (similar to modeling aggregate load response). The work of the SPIDERWG provides technical references and industry best practices: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group does not agree that the modifications made in MOD-032-2 will improve system modeling and reliability for the reasons stated by both EEI and the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. See responses to EEI and MRO NSRF.

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No

Document Name	
Comment	
Tri-State Generation and Transmission supports the MRO NSRF Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to MRO NSRF.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The MRO NSRF believes that the modifications made to MOD-032-2 will have very limited impact on improving system modeling and reliability. The fact remains that, TOs and DPs have no ability to compel DER owners to provide the data that would be necessary to significantly improve system modeling and reliability. This provides (in our opinion) a likely scenario under which a NERC-registered entity may be held to have a compliance gap for the non-performance/compliance of a non-NERC-registered entity. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes every residential solar and commercial rooftop solar customer on the DP's systems. This would likely impose an immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	

Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent. 3C: Minimum threshold The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Accurate modeling of significant DER facilities would improve system modelling and reliability. However, requiring the modeling of facilities where modeling data is not available could just as easily harm the reliability of the transmission system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 3B: Data accuracy It is understood that modeling aggregate DER (based on collected data) will involve some assumptions (similar to modeling aggregate load response). The work of the SPIDERWG provides technical references and industry best practices: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	

Answer	No
Document Name	
Comment	
Through various reports, NERC has displayed how IBR can have an impact on the BES, but it is unclear how the aggregation of smaller “R-DER” impacts the BES in a manor proportional to “U-DER”. Total aggregated R-DER penetration is far from equivalent to a few “U-DER” installations across a utility’s footprint. Much of the required information is not available to DP’s for smaller DER installations and the ability to require the information from interconnectors is authorized by RERRA entities. The assumptions required to try to model R-DER due to MOD-032-2 requirements could also lead to false confidence and support of the BES from R-DER sources. A threshold is needed, suggested at 1 MW, for DER installations to differentiate the discrete modeling of resources with steady state and dynamic information vs. aggregating DER below such threshold, providing gross nameplate values, and allowing the PC to determine approximated DER response to system events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 3B: Data accuracy It is understood that modeling aggregate DER (based on collected data) will involve some assumptions (similar to modeling aggregate load response). The work of the SPIDERWG provides technical references and industry best practices: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf. 3C: Minimum threshold The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	

Answer	No
Document Name	
Comment	
The benifit of this additional data will have to be explained better. We are unclear of why it is important. The scope should only include what is directly connecting into Transmission System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SC has already determined this was important by approving the SAR and project. The work of the SPIDERWG provides technical references and industry best practices: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf. Additionally, numerous disturbance reports where DER impact was significant have been published, including but not limited to: https://nercstg.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf https://nercstg.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
It depends on the applicability of generators. If there is a threshold then Constellation agrees on improvement to reliability but a blanket statement will be overly burdensome with minimal to no improvement on reliability for projects smaller than 20 MVA. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	

Response

Thank you for your comments.
3C: Minimum threshold
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE believes the proposed revisions to MOD-032-2 are problematic and contradicts the existing data requirements that have already been established by the local Planning Coordinators in coordination with Transmission Planners. For example, in the ERCOT region, ERCOT defines these data requirements through the coordination with Transmission Planners as part of various regional working groups. The already defined data requirements do not align with the proposed revisions of the Data Reporting Requirements in MOD-032-2 (ex. Attachment 1, item 2, footnote 2). The current MOD-032-1 addresses and includes the requirements around DER data.

CEHE is in support of EEI's comment that the modifications made to MOD-32-2 "continue to obligate TOs and DPs to provide data that exceeds their ability to obtain." CEHE agrees with EEI in that if this data is needed, the resource owners should be registered and obligated to supply the data, not the TOs or DPs.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The DT agrees that local PC/TP requirements per Requirement R1 may need to be updated to incorporate DER data, but such requirements are still established by the local PC/TP so MOD-032-2 will not contradict the PC/TP requirements. MOD-032-2 highlights PC/TP flexibility in developing data requirements and reporting procedures in both Footnote 2 and footnote 4. The SC already determined that MOD-032-1 was not sufficient to address DER data by approving the SAR and project. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy believes that the modifications made to MOD-032-2 will have very limited impact on improving system modeling and reliability. The fact remains that, TOs and DPs have no ability to compel DER owners to provide the data that would be necessary to significantly improve system modeling and reliability. This provides (in our opinion) a likely scenario under which a NERC-registered entity may be held to have a compliance gap for the non-performance/compliance of a non-NERC-registered entity. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes every residential solar and commercial rooftop solar customer on the DP's systems. This would likely impose an immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.	
Likes 0	
Dislikes 0	
Response	

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

3C: Minimum threshold
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

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 the opportunity to comment, and offers the following.

1. While BC Hydro appreciates the intent of modifications made in MOD-032-2, BC Hydro is of the opinion that the intended improvement in system modeling and reliability cannot be realized, until the implementation of an effective and practical approach to collect accurate DER data in a timely manner and with a sufficient level of detail. This would be challenging due to the lack of any compliance obligations on unregistered DER owners. DP and TO may have some leverage, such as introducing obligations for DER owners to provide acceptable data for future DERs before they can be connected to the DP/TO systems. However, in the case of unregistered DER owners that are already connected to a TO/DP, the TO/DP will have an extremely limited ability to ensure a timely collection of such data, its accuracy, and sufficient level of detail.

2. The Footnote 5 of the Attachment 1 states that "Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information". This appears to set a

mandatory requirement, which – as outlined above – would impose regulatory compliance obligations the TO and/or DP registered entity may be unable to meet.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	No
Document Name	
Comment	
Clarification is needed with the changes outlined in Attachment 1 in the Steady-State column of Table-#9: 1. "b. Real power capability" • Is this referring to the nameplate or approved capacity? 2. "c. Generator type (solar, battery, etc.)" • Oncor recommends modifying this statement to give instructions on how to report a single location with multiple types of DER. 3. "d. DER capabilities related to ride through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes." • Could the SDT elaborate on how frequency control would impact the Steady State modeling?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Details about how data is to be reported is specified by the PC/TP per Requirement R1. SPIDERWG has published numerous reliability guidelines and white papers related to representing DER https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf. The DT contends that it is not appropriate to mandate a specific DER representation in MOD-032. 6G: Move control capabilities to dynamics? As noted in the Technical Rationale, the DT maintained the approach from MOD-032-1 where detailed sub-bullets are only presented in the "steady state" column although such information may also be relevant to "dynamics" or "short circuit." In general, information about control and ride-through capabilities could be used to inform steady state behavior assumptions.	
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	
Thank you for your comments. See response to EEI.	
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	
Thank you for your comments. See response to MRO NSRF.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy's official response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
While SPP believes that the proposed modifications are a good step towards improving system modeling and reliability. However, we still have concerns around the appropriate data collection process pertaining to DERs.	

We recommend that the UFLS-Only DP be added to the applicability section of the standard as these registered entities are just as likely to have DERs connected to their system. From our perspective, adding the UFLS-Only DP will eliminate the possibility of uncaptured DER load data if a DP does not have access to this data	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 3F: Add UFLS-only DP to applicability The DT agrees that adding "UFLS-Only Distribution Provider" to MOD-032-2 applicability would reduce (but not necessarily completely eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, consultation with NERC legal staff indicated that adding UFLS-Only Distribution Provider to the applicability would not be appropriate at this time.	
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	
The modifications do not address the true reliability gap in that GOP and DPs are not by the NERC ROP obligated to align to a TP. The language should be adjusted in R2 to state that the BA et all shall provide... to the TP of the interconnected Transmission system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. This issue seems beyond the scope of the SAR.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	
ATC appreciates the intent of modifications contained in MOD-032-2. However, as Draft 2 of the Standard is written, TOs and DPs have no mechanism to compel the actual DER owners to provide the data that would be necessary to significantly improve system modeling and reliability. Compliance-related questions: Please clarify what the compliance implications are if a TO/ TP or DP requests the modeling data but does not receive it or if the data is inaccurate? Will showing that the TO/ TP attempted to request data be enough? Or that the TO/ TP utilized (or at least considered) the data received if no collection and modeling thresholds are set? Please clarify how the TO/ TP or DP should be aware that DER are connected to an unregistered DP? The TO/ TP and DP would not have insight into those systems. Please clarify the obligations of the TO/TP and DP in determining who is next closest electrically to each unregistered entity (DP or TO) as listed in Footnote 5? Does the TO/TP or DP need to reach out to the DER or to the unregistered DP for the information? Would the request for DER information be an annual process or triggered by something else?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent. 6D: issues with "next electrically closest" - need clarification Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale.	

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) and MRO NSRF for question #3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to EEI and MRO NSRF.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
If DER penetration levels are high in a particular area, the changes in MOD-032-2 could have a positive impact on reliability. However, if DER penetrations are not high enough to impact the reliability of the BES, DPs and TOs will have added unnecessary administrative work and compliance burden for the purpose of checking a compliance box.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 3C: Minimum threshold	

The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
It depends on the applicability of generators. If there is a threshold then Constellation agrees on improvement to reliability but a blanket statement will be overly burdensome with minimal to no improvement on reliability for projects smaller than 20 MVA. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 3C: Minimum threshold The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.	
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; John Nierenberg, 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	
The new requirements for DER data do not appear to directly correlate with the fields in existing modeling software such as the Composite Load Model (CMPLDWG). Tacoma would prefer for the Requirements to either align with existing modeling software, or for there to be a guidance document outlining what additional new software/model development needs to take place before the required DER can actually be utilized. The most significant concern is that there are often multiple installations of DERs connected to each substation, where each DER has unique ride-through and voltage control capabilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. In general, DER can be adequately represented in most common software packages. SPIDERWG has published a White Paper specifically related to simulation software: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Software_Vendor_DER_Recommendations_SPIDERWG_postPubs.pdf as well as numerous other documents related to DER modeling: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
The revisions should also note that if the Planning Coordinator or Transmission Planner can obtain the information directly from the generator based on individual ISO Tariff or other local requirements that the TO or DP does not need to provide information listed in Attachment 1. Suggested revision is redlined below.	

For steady-state:

9. Distributed Energy Resource (DER) data [DP, TO where DER is directly connected to the TO system and not through a DP unless the generator is required to provide the data directly to the PC or TP based on individual Tariff or local provisions]

a. Location (bus from item 1)

b. Real power capability

c. Generator type (solar, battery, etc.)

d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.

For dynamics:

10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP, unless the generator is required to provide the data directly to the PC or TP based on individual Tariff or local provisions]

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
3H: Availability of data through alternative methods - move from TR to standard?
This concept is addressed in the Technical Rationale to provide flexibility to PC/TP in ensuring necessary data is available. Data collection requirements for DER in MOD-032 are focused on what is necessary for reliability and may differ from the data collected via an individual Tariff or local provisions.

Ben Hammer - Western Area Power Administration – 1	
Answer	No
Document Name	
Comment	

The modifications made to MOD-032-2 may have limited impact on improving system modeling and reliability. However, TOs and DPs have no ability to compel DER owners to provide the data that would be necessary to significantly improve system modeling and reliability. The changes create a likely scenario under which a NERC-registered entity may be held to have a compliance gap for the non-performance/compliance of a non-NERC-registered entity.

The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes every residential solar and commercial rooftop solar customer on the DP's systems. This would likely impose an immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

3C: Minimum threshold
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	

Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT views the collection of DER data from registered DPs as improving reliability. The DT does not agree that there is no improvement simply because there is a potential gap with unregistered Distribution Providers. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
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 believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT views the collection of DER data from registered DPs as improving reliability. The DT does not agree that there is no improvement simply because there is a potential gap with unregistered Distribution Providers. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.	
Likes 0	

Dislikes 0	

Response

Thank you for your comments. The DT views the collection of DER data from registered DPs as improving reliability. The DT does not agree that there is no improvement simply because there is a potential gap with unregistered Distribution Providers.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller

Answer	No
Document Name	

Comment

Black Hills Corporation believes that the modifications made in MOD-032-2 will not improve system modeling and reliability as unregistered DPs are still not required to provide DER information. Additionally, the language changes impose regulatory compliance risk onto registered TO, or DP entities that are the "next closest electrically connected registered entity" to the unregistered DPs.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The DT views the collection of DER data from registered DPs as improving reliability. The DT does not agree that there is no improvement simply because there is a potential gap with unregistered Distribution Providers.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the proposed changes to MOD-032-2 because many of the changes would obligate TOs and DPs to provide data that exceeds their ability to obtain. EEI further notes that during the Fall 2023 NPCC Compliance and Reliability Conference a presentation titled "Inverter Based Resource Work Plan" was given and appears to use data from a Berkeley National Laboratory Report. The presentation goes on to indicate that BES IBRs (75MW at ≥100kV) account for 84% and non-BES (≥20MW & ≤75MW at ≥100kV plus ≥MW at <100kV) account for an additional 14%; for a total of 98% of the IBRs currently interconnected on the grid. This data additionally indicates that small IBRs (<20MW at any kV) only account for 2% of the connected IBRs and if correct, would mean these resources would have no meaningful impact on the Reliability of the BPS. Moreover, in FERC Order No. 901 (Reliability Standards to Address Inverter-Based Resources), the Commission made it clear that the focus of changes to NERC Reliability Standards, as it relates to modeling of DERs, is to be limited data to aggregate data not granular details on a non-aggregated basis. Given the NPCC data and FERC Order No. 901, it would indicate that many of the proposed changes to MOD-032 are unnecessary for reliability. This would include modifications to MOD-032 that propose to provide PCs/TPs with the authority to request data that is overly granular and unnecessary to model the impacts of DERs on the BPS. IBRs that have a meaningful impact on the BPS should be registered. Once this has been done, PCs and TPs could seek the data they need directly from the registered resource, not the TOs or DPs that are unlikely to have the needed data. While we recognize the need to	

gather and model the impacts of DER resources on the distribution system, modeling should be limited to load demand and aggregate DER impacts/offsets. However, we do support obligating DER Aggregators who are participating in the organized markets to provide data on their aggregated resources to the PCs/TPs upon request. We do not support obligating TOs and DPs to gather non aggregated data, upon request.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Response to similar comment related to modeling details + 4D & 6T themes: The DT contends that DPs should already have a record and basic understanding of DER that is connected to their system (e.g., rooftop solar, batteries, etc.) similar to how they have a record and basic understanding of houses, factories, and commercial spaces connected to their system. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. The DT does not believe that the development of essential requirements related to ensuring appropriate DER data is available to PCs and TPs should be delayed to put the industry behind the curve as they are with IBR performance requirements. The DT believes this is aligned with the urgency conveyed in FERC Order No. 901. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No

Document Name	
Comment	
We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them. Also, we believe either a DP or TO who has another entity interconnecting with them has a marketing responsibility of modifying their Interconnection requirements if they deem it necessary for reliability in their BA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES, EEI, MRO NSRF, NAGF, and Talen.	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Hi, please reference comments by Marty Hostler, NCPA Compliance Manager. Thank you, **Jeremy Lawson, P.E.** Generation Services Director of Engineering Northern California Power Agency	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to comments by Marty Hostler, NCPA Compliance Manager.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP thanks the SDT for adding the text in footnote 5 which states "…Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through ***available*** information" and request that clarity be provided on exactly what is meant by "available information?" AEP believes that information that is requested (and perhaps even exists) but is not provided by the data owner should be considered unavailable. In addition, this scenario should be added to the others listed in the Technical Rationale document.

Notwithstanding the SDT's response to our previous suggestion, AEP continues to believe that the best path forward for this proposed standard would be for those entities providing power at a minimum threshold to be registered as a Functional Entities and to provide DER data. We recommend that the SDT establish an aggregate minimum threshold, similar to what was recently proposed by NERC in regard to IBRs. As is the case in existing standards where Generator Owners are obligated to provide similar data, entities who possess the needed DER data noted in the Attachment One revisions should likewise be registered and explicitly obligated to provide this data as well. While we are unsure if the existing Functional Entities classes are themselves sufficient, or if instead, a new class of Functional Entities might need to be considered and developed, the need nonetheless exists. NERC may wish to also consider the potential that such obligations could potentially cross Federal and State jurisdictional lines of responsibility, further illustrating the complexity-of and challenges-in developing obligations to obtain the DER data in the revised Attachment One.

Likes 0	

Dislikes 0	

Response

Thank you for your comments.
2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

3C: Minimum threshold
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf. It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

In principle, getting more “reasonably accurate” DER models into the regional models should help to improve reliability. There could be some risk to reliability if DER dispatch in models is higher than expected as this could mask load serving reliability issues. MOD-032 regional model building groups need to provide guidelines on what level of DER should be included in each seasonal model. Studying appropriate sensitivity cases should be part of TPL-001 scope.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The DT agrees with the comment. The intent of MOD-032-2 is to ensure DER data is available for inclusion in PC/TP studies. Assessing the reliability impacts of DER are within the scope of the second phase of Project 2022-02 covering TPL-001 modifications.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF believes that including DERs will improve system modeling and reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	Yes
Document Name	
Comment	
The latest draft of MOD-032 no longer requires reactive power information to be collected for DERs. While most smaller systems really only operate at unity, it is the belief of NCEMC having this information will allow planners to more accurately model Distributed Energy Resources, thereby improving grid reliability. Thus, NCEMC recommends that reactive power data collection for DERs be required by MOD-032.	
Likes 0	

Dislikes 0	

Response

Thank you for your comments.
2C: elimination of reactive power
The DT removed the reactive power capability in response to previous industry comments. A DER's reactive power operating characteristics can depend on many factors aside from the maximum capability, including the mode of reactive power control. For instance, if the DER is in volt/var control mode, the distribution system loading, voltage regulation scheme, and impedance can all affect the DER's reactive power output. The Attachment 1 information provides a minimum baseline for information. The PC/TP may request additional information to make assumptions about aggregate DER reactive power operating characteristics.

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2

Answer	Yes
Document Name	

Comment

The SRC believes there is an urgent need to move forward with collecting DER data now. Additional DER data collection activities will be needed as the penetration of DERs increases; however, these modifications are a step in the right direction and more can be done over time. The revisions should also note that if the Planning Coordinator or Transmission Planner will obtain the information directly from the generator based on individual ISO Tariff or other local requirements that the TO or DP may not need to provide information listed in Attachment 1. Suggested revision is redlined below.

For steady-state:

9. Distributed Energy Resource (DER) data [DP, TO where DER is directly connected to the TO system and not through a DP ***unless the generator will provide the data directly to the PC or TP based on individual Tariff or local provisions****]*

a. Location (bus from item 1)

b. Real power capability

c. Generator type (solar, battery, etc.)

d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.

For dynamics:

10. Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP, ***unless the generator will provide the data directly to the PC or TP based on individual Tariff or local provisions****]*

Likes 0	
Dislikes 0	

Response

Thank you for your comments. 3H: Availability of data through alternative methods - move from TR to standard?
This concept is addressed in the Technical Rationale to provide flexibility to PC/TP in ensuring necessary data is available. Data collection requirements for DER in MOD-032 are focused on what is necessary for reliability and may differ from the data collected via an individual Tariff or local provisions.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment

While the acquisition and utilization of DER data by the PC/TP for the purposes of power system modeling should enhance the PC/TP's ability to study future scenarios and develop plans accordingly, we are concerned with the future compliance interpretation for Requirement R4. That is, how might the ERO (or its designee) modify its expectation for Interconnection-wide case(s) in regard to DER data?

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Per R4, the PC "shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area." In other words, DER data provided to the PC shall be made available for inclusion in Interconnection-wide cases.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
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.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
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.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
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 Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
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.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
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.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

4. Do you agree the modifications made in MOD-032-2 are cost effective?	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Hi, please reference comments by Marty Hostler, NCPA Compliance Manager. Thank you, **Jeremy Lawson, P.E.** Generation Services Director of Engineering Northern California Power Agency	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to comments by Marty Hostler, NCPA Compliance Manager.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	

We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them.

Additionally, the SDT has not stated a cost or benefit to said modifications. 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, simply someone says there is a reliability gap, or a risk, but does not provide estimated tangible reliability indices improvement numbers or a cost to fill the alleged gap or risk, is not good justification to create another costly administrative process.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. See responses to ACES, EEI, MRO, NAGF, and Talen.

The intent of the question is to solicit industry feedback on potentially more cost-effective ways to meet the reliability objective for DT consideration. The SC has already established the reliability need by approving the SAR and project. The work of the SPIDERWG provides technical references and industry best practices related to DER: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf. Additionally, numerous disturbance reports where DER impact was significant have been published , including but not limited to:
https://nercstg.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf
https://nercstg.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment

AEPC signed on to ACES comments:

It is our opinion that, as written, the proposed changes are not cost effective. It is our belief that requiring the DP to collect data for all DER/IBR resources, without regard to size and/or reliability impact, will create an unnecessary compliance burden and only provide a marginally increased reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.	
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 our opinion that, as written, the proposed changes are not cost effective. It is our belief that requiring the DP to collect data for all DER/IBR resources, without regard to size and/or reliability impact, will create an unnecessary compliance burden and only provide a marginally increased reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit	

For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.	
Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	
Comment	
The latest draft of MOD-032 no longer requires reactive power information to be collected for DERs. While most smaller systems really only operate at unity, it is the belief of NCEMC having this information will allow planners to more accurately model Distributed Energy Resources, thereby improving grid reliability and potentially allowing for solutions which reduce cost by taking DER reactive power capability into account. Thus, NCEMC recommends that reactive power data collection for DERs be required by MOD-032.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2C: elimination of reactive power The DT removed the reactive power capability in response to previous industry comments. A DER's reactive power operating characteristics can depend on many factors aside from the maximum capability, including the mode of reactive power control. For instance, if the DER is in volt/var control mode, the distribution system loading, voltage regulation scheme, and impedance can all affect the DER's reactive power output. The Attachment 1 information provides a minimum baseline for information. The PC/TP may request additional information to make assumptions about aggregate DER reactive power operating characteristics.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No

Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
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. *The NAGF requests that the SDT address the process under MOD-032 to require the TP/PC to request data each year rather than require the GO to go look for and follow TP/PC process. If reliability is really the goal, an active request for data is likely to receive a much higher response rate than expecting those that need to supply information to go looking for when, where and how they need to provide it. The NAGF believes that it is extremely costly for hundreds of entities to go looking for information to determine when they need to provide data than it is for a few entities to send out emails requesting the information.*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. This issue of PC/TP processes appears to be beyond the scope of Project 2022-02. The DT has not proposed any new requirements for NERC registered GOs.	

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Inclusion of small DERs is extremely cost burdensome for Generator Owners. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
As previously stated, if DER penetration levels are high in a particular area, the changes in MOD-032-2 could have a positive impact on reliability. However, if DER penetrations are not high enough to impact the reliability of the BES, DPs and TOs will have added unnecessary administrative work and compliance burden for the purpose of checking a compliance box. Additionally, if the TO/DP is required to report data that the DER owner has no obligation to provide, the standard should address how the RE intends to handle situations where the	

unregistered Distribution Provider does not provide the requested data to the registered DP or TO. Otherwise, the TO/DP may be subject to fines and penalties for non-compliance related an issue that is beyond the control of the TO/DP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
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 for question #4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to MRO NSRF.	

LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC does not believe that MOD-032-2 Draft 2 is cost effective as it is written. The requirements would likely impose a huge administrative burden on the NERC Registered DPs and TOs potentially requiring additional staff.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
Because so many issues around DERs, IBRs and ESRs remain unresolved and will be dependent upon final requirements for DERs, it is difficult to address the cost effectiveness of the MOD-32-2 modifications. We do believe that software upgrades will be required to collect data on DERs, IBRs, and ESRs that have the potential to create cost increases for many in the industry.	

Furthermore, we recommend the drafting team take into consideration evaluation the cost effectiveness from the FERC Order 2222 and IEEE Standards (1547 and 2800) perspectives.	
Likes 0	
Dislikes 0	
Response	
Thank you for the recommendation.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy's official response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
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	
Thank you for your comments. See response to MRO NSRF.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES and MRO NSRF.	
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	
Thank you for your comments. See response to EEI.	

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer	
Answer	No
Document Name	
Comment	
• Cost-effectiveness depends on the level of assumptions TOs/TPs are allowed to make in the DER data modeling. If high precision in data collection is required, this will take a resource's time, which will increase costs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4D: Issue with unregistered entities (DP and/or DER) or detailed modeling The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES:	

It is our opinion that, as written, the proposed changes are not cost effective. It is our belief that requiring the DP to collect data for all DER/IBR resources, without regard to size and/or reliability impact, will create an unnecessary compliance burden and only provide a marginally increased reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV ENERGY does not agree that the modifications in MOD-032-2 are cost effective. As proposed MOD-032-2 would likely impose a immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit	

For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
The effort required to model all DER's, regardless of size, is considerable and likely not achievable with non-registered entities. This is likely an exercise until additional regulations are in place requiring information at appropriate levels.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4D: Issue with unregistered entities (DP and/or DER) or detailed modeling The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	

Inclusion of small DER's is extremely cost burdensome for generator owners. Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	

Comment
The effort required to model all DER’s, regardless of size, is considerable and likely not achievable with non-registered entities. This is likely an exercise until additional regulations are in place requiring information at appropriate levels.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. 4D: Issue with unregistered entities (DP and/or DER) or detailed modeling

The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
The effort required to model all DER's, regardless of size, is considerable and likely not achievable with non-registered entities. This is likely an exercise until additional regulations are in place requiring information at appropriate levels.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4D: Issue with unregistered entities (DP and/or DER) or detailed modeling The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No

Document Name	
Comment	
No it requires a huge amount of effort that is why we need to have a clearly defined scope and a better defined process for registering non-registered DPs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 4B: Too much TO/DP (and GO?) burden - not enough reliability benefit For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5. 4D: Issue with unregistered entities (DP and/or DER) or detailed modeling The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	

The administrative burden to provide accurate modeling of aggregated R-DER does not outweigh marginal modeling benefits. It is recommended NERC focus on utility scale DER and assuming little to no support from residential DER during system events. A compromise may be to add a threshold for the steady state and dynamic modeling requirements in MOD-032-2 and allow all other DER to be aggregated gross nameplate values reported by DP/TO entities which the PC can determine modeling parameters for based on industry research.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. 4C: Threshold needed for cost effectiveness The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	

Comment
It’s unclear how much work will be needed to develop the models. We don’t see the modifications made since the last draft is changing the cost effectiveness.

Likes 0	
Dislikes 0	

Response

Thank you for the comment.	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
We will not be able to assess the cost effectiveness of this process until the resulting procedure changes at MISO are finalized and we understand data requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
MRO NSRF does not agree that the modifications in MOD-032-2 are cost effective. As proposed MOD-032-2 would likely impose a immense administrative burden on (NERC Registered) Distribution Providers and Transmission Owners, while not delivering significant reliability benefits.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
4B: Too much TO/DP (and GO?) burden - not enough reliability benefit	

Thank you for your comments. For the same reasons that MOD-032 and TPL-001 are being revised to account for DER data needs and potential impacts on the bulk power system, the DT understands that the TO/DP also has a reliability need for visibility into the types and amounts of DER connected to their electric systems. Burden will be reduced as a consequence of modification to Footnotes 4 and 5.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission supports the MRO NSRF Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to MRO NSRF.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group does not agree that the modifications made in MOD-032-2 are cost effective for the reasons stated by both EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to EEI and MRO NSRF.	

Donald Lock - Talen Generation, LLC - 5	
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	
Thank you for the comment.	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Things appear to be specultive at this point.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	

Comment	
Until the intent of obligations assigned to the Applicable Entities are clear, FirstEnergy cannot determine the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

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; John Nierenberg, 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	
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.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
We offer no opinion on the cost effectiveness of the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	
Answer	
Document Name	
Comment	
No comment.	
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	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	

Black Hills Corporation will not provide comment on cost effectiveness.	
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 will not provide comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation will not provide comment on cost effectiveness.	
Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren has no comments on cost effectiveness of this project	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the Implementation Plan for revised MOD-032-2?	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Until the intent of obligations assigned to the Applicable Entities are clear, FirstEnergy cannot support the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP believes additional time will be needed to accommodate the work pertaining to assets newly brought into scope. Rather than being required to comply with the obligations 12 months after the definition has become effective, we instead suggest it be 24 months after the definition has become effective.	
Likes 0	
Dislikes 0	

Response
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group does not agree with the Implementation Plan for the reasons stated by both EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	

Response
Thank you for your comments. See responses to EEI and MRO NSRF.

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	

Tri-State Generation and Transmission supports the MRO NSRF Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to MRO NSRF.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It The PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide the data to the PC/TP. The Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the	

Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
If MOD-032-2 is approved as-is, utilities will need to increase resourcing to accommodate the additional modeling complexities and data collection. DP's, in particular, may not have staffing experience in dynamic modeling, which would lead to a need to establish contractors with the experience or hire/train internal staff. The ability to request the level of information to create dynamic models of DER also falls to the authority of RERRAs. Depending on the existing interconnection procedures, state or local government authorities may need to approve revisions to interconnection requirements. 12 months after the approval date is too soon to require compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	No

Document Name	
Comment	
DER definition needs to be clarified first.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to question #1 related to the proposed DER definition.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not support of the proposed changes to MOD-032-2 and therefore cannot support the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It The PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide the data to the PC/TP. The Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
5A: 12 months for data obligations is too short (18-36 months)
As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye Power, Inc. supports the comments of ACES:

The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It is surprising to us that the PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect

and provide it to the PC/TP. We believe that the Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Based on the rationale provided in our response to Question 3 above, BC Hydro is unable to support the proposed Implementation Plan at this time.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. See response to your comment on question #3.	
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	
Thank you for your comments. See response to EEI.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES and MRO NSRF.	
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	
Thank you for your comments. See response to MRO NSRF.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy's official response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP recommends that the implementation of Requirements R2, R3 and R4 become effective 24 – 36 months after the implementation of Requirement R1. In order for industry to implement these changes we believe it will require a large transitional curve for requesting and providing the data. Newly impacted entities will need time to transition and ensure that the new process is efficient and reliable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
While ATC does not have any particular concerns with the timing outlined in the implementation plan as proposed, we are opposed to the rest of the standard and DER definition as written, and its associated responsibilities, we therefore do not agree with the implementation plan of the proposed version.	
Likes 0	

Dislikes 0	
Response	
Thank you for your 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 MRO NSRF for question #5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to MRO NSRF.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
It is not prudent to agree with the implementation plan until the standard addresses how the RE intends to handle situations where the unregistered Distribution Provider does not provide the requested data to the registered DP or TO.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It The PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide the data to the PC/TP. The Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	

Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Scott Brame - Scott Brame On Behalf of: Chris Dimisa, North Carolina Electric Membership Corporation, 4, 3, 5; Reid Cashion, North Carolina Electric Membership Corporation, 4, 3, 5; Richard McCall, North Carolina Electric Membership Corporation, 4, 3, 5; - Scott Brame, Group Name NCEMC	
Answer	No
Document Name	

Comment	
NCEMC support comments of ACES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to ACES.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon concurs with the comments submitted by the EEI.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
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	
The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It is surprising to us that the PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide it to the PC/TP. We believe that the Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the proposed changes made to MOD-032 and therefore cannot support the Implementation Plan at this time as a result.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments: The timeline proposed in the Implementation Plan is not long enough for Requirements R2, R3, and R4. It is surprising to us that the PCs and TPs are given 24 months to develop their data requirements, yet the entities required to submit said data are only given 12 months to collect and provide it to the PC/TP. We believe that the Phased-In Compliance Dates for R2, R3 and R4 should be extended to at least 18 months (preferably 24 months) after the effective date of MOD-032-2.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
As explained in our comments on Draft 1, we suggest the implementation plan be revised to allow 24 months (rather than 12 months) after the effective date for the initial performance of R2, R3 and R4. The drafting team's "expectation" that TOs and DPs would participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of R1, thereby allowing TOs and DPs to start working on data collection processes and methods more than 12 months prior to the effective dates of R2, R3, and R4 is not assured.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 5A: 12 months for data obligations is too short (18-36 months) As noted in the Project 2022-02 10/30/2023 Webinar, TOs and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to	

start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported. Further, "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. The DT believes that industry concerns related to the level of required DER modeling detail may be driving industry suggestions for longer implementation times and are addressed by these modifications.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
It should not be implemented as currently drafted and until a cost benefit analysis is provided.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to your comment on question #4 regarding cost/benefit analysis.	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Hi, please reference comments by Marty Hostler, NCPA Compliance Manager. Thank you,	

Jeremy Lawson, P.E. Generation Services Director of Engineering Northern California Power Agency	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to comments by Marty Hostler, NCPA Compliance Manager.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
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	

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	

Answer	Yes
Document Name	
Comment	
Constellation has no additional comments Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF supports the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern supports the comments by EEI on potential implementation challenges.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
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.	
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.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Martin Sidor - NRG - NRG Energy, Inc. - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
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.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
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	
Thank you for your support.	
Ruchi Shah - AES - AES Corporation - 5	
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.	
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.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, 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	
Thank you for your support.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
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.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
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.	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	

Document Name	
Comment	
Hard to tell at this point.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
no comment	
Likes 0	
Dislikes 0	
Response	

6. Provide any additional comments for the standard drafting team to consider, if desired.	
Apollonia Gonzales - PNM Resources - Public Service Company of New Mexico - NA - Not Applicable - WECC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
We agree with some comments provided by ACES, EEI, MRO, NAGF, and Talen but are not going to restate each item specifically, as others have already restated them. Area coordinators are already responsible for submitting data for modelling, they should be getting data they feel they need; not what some other entity tells them they should get. If a PA needs data they should be responsible for getting said data. Further, if said data is needed, then the BA and/or the TO or DP should modify and/or enforce their market and/or interconnection rules to require load and/or generation entities (Utilities interconnected to a BA's area) provide said data. It appears we are trying to draft new standards continent wide for local issues.	

Additionally, each Utility is already required to complete an EIA-861 form annually. We suggest that the entity needing said data use data that is already on those spreadsheets and use a macro to populate each year's data (which EIA already has) with the bus numbers for each utility so it can be used with a composite load model for each bus. The entity needing the data can call each utility or the TO that services them in order to get the appropriate bus number. We feel there is more man-hours being spent talking about the issue and trying to develop a standard then it would take the entity that wants the data to call and find out the bus numbers to assign to data that already exists. Then the entity needing said data can get it annually from the public EIA website and run a macro to insert the bus numbers. Much simpler and less costly for everyone.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES, EEI, MRO, NAGF, and Talen. 6W: Data is already available to entities that need it The SC approved the DT and the SAR which includes modification of MOD-032 to specifically add DER data in its scope. The DT has taken care to not be overly prescriptive in allowing the PC/TP flexibility in specifying data reporting requirements aligned with local needs.	
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 for your comments. See response to NPCC Regional Standards Committee.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

Comments on "Attachment 1":

Footnote 2 is concerning since the way we collect and forecast aggregate load data is metering that is unaware of any DER impacts. The suggestion in the technical rationale isn't possible to do cleanly. ("*In situations where DER is not separately metered, a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. A consistent reduction in load on the feeder may be indicative of DER interconnections.")*

We would prefer the standard more explicitly allow for estimation by either reported DER nameplate capacity, or by estimated % of load (i.e., if no better information is available, perhaps use the data you do have to estimate DER as a % of peak load).

Dynamics reporting requirement # 10 reads:

"*Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS [DP, TO where DER is directly connected to the TO system and not through a DP]*"

The added detail here is more burdensome, and is almost certainly not going to be available. The technical rationale says:

"*The SDT intentionally maintained flexible language as to whether the underlying DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources*."

However the addition of requirements for more specific data seems to go against the characterization that "estimated quantities" are acceptable.

Steady-state reporting requirement #9 has a footnote 4 that reads:

"*The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.*"

The implication here about determining the equivalent distribution system impedance to DER is perplexing. First because steady-state models do not model distribution impedance. In most cases, everything (including the main distribution transformers) is lumped into the aggregate load. This does apply to dynamic load models that consider equivalent distribution system impedances, but there is no practical way to vary that for every DER. And this is inconsistent with the approach used to model motor loads. For example, there is no requirement to report every individual motor and the equivalent impedance to that motor. And one could argue that the motor load has a vastly more important effect on the system than DER. TPL-001-5.1 stipulates the use of dynamic load models for Stability analysis but allows for the use of an aggregate System Load model. No further details or requirements. Studies are extremely sensitive to the load model that's used. If it is okay to develop those load models in estimated, aggregate form, why should there be anything more expected for DER?

Our general feeling is that the proposed modifications for DER data is getting too detailed and there needs to be very clear and explicit language that says estimating aggregate DER data is acceptable if more detailed data is not available.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
6U: more explicitly allow estimates related to FN2 (related to theme 6B)
Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale.

6V: Estimated quantities related to UVLS/UFLS & DER

Knowledge of whether DER is subject to trip by UFLS/UVLS relays is necessary for proper development of UFLS/UVLS schemes as described in the SPIDERWG documents referenced in the Technical Rationale. 6S: FN 4 aggregation level - standardize/specify? Clarify modeling detail? The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
The phrase “where DER is directly connected to the TO system and not through a DP” in steady state item 9 (and dynamics item 10) from Attachment 1 may not be consistent with footnote 5. ERCOT recommends simplifying the responsibility assignment in steady state item 9 (and dynamics item 10) to “[DP, TO]” and modifying footnote 5 to read as follows: **The registered entity (TO or DP) to which DER is connected is responsible for reporting DER data in accordance with PC/TP modeling data requirements and reporting procedures developed under Requirement R1.** Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

6I: Separate registration for TO with DER?/clarify TO obligation & FN5 Footnotes 4 and 5 were combined and modified to add clarity and a more detailed description of the DT intent was added to the Technical Rationale.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	

AEPC signed on to ACES comments:

We have a great deal of apprehension as it relates to proposed language in Footnote 5 of Attachment 1. Footnote 5 states (emphasis added):

"Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column."

By what method should it be determined which registered entity is the "next closest electrically connected". Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the "next closest electrically connected" and how? In order to make this determination, a certain amount of knowledge about the other entity's infrastructure is required.

Of even greater concern is the continued inclusion of data from unregistered entities despite the open acknowledgment by the SDT of the challenges with collecting said data (see Technical Rationale, paragraph 2). We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved and can be included in the next draft of MOD-032-2.

Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 6D: issues with "next electrically closest" - need clarification Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale. 6E: GO-IBR to the rescue (related to theme 1D) The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI notes that this project has been listed as a low priority project. While we understand this may have some immediate impacts on the work being conducted by this SDT, we suggest that a two phased approach for the revision of MOD-032 might address the immediate concerns surrounding efforts to align registration under Project 2017-02. Phase 1: Consider completing the work from project 2017-02 Standards	

Alignment with Registration: Replace Load-Serving Entity (LSE) with Distribution Provider (DP), remove the Planning Authority (PA) functional entity name and keep the Planning Coordinator (PC) functional entity name, and make the associated LSE / DP functional changes to the standard requirements. Phase 2: Please consider addressing additional DER data requirements, after further discussion regarding how GO-IBR and GOP-IBR standards are going to be addressed and what is needed from Distribution Providers regarding unregistered IBRs. In addition to the comments responding to the questions above and our suggests related to project phasing, we are additionally concerned with Attachment 1, Footnote 5 and suggest it should be deleted because the next closest DP or TO to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.	
Likes 0	
Dislikes 0	

Response

Thank you for your comments.
6T: Prioritize administrative issues with MOD-032/Wait for 901
The DT does not believe that the development of essential requirements related to ensuring appropriate DER data is available to PCs and TPs should be delayed to put the industry behind the curve as they are with IBR performance requirements. The DT believes this is aligned with the urgency conveyed in FERC Order No. 901.

6E: GO-IBR to the rescue (related to theme 1D)
The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.

6D: issues with "next electrically closest" - need clarification
Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	

We have a great deal of apprehension as it relates to proposed language in Footnote 5 of Attachment 1. Footnote 5 states (emphasis added):

"Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column."

By what method should it be determined which registered entity is the "next closest electrically connected". Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the "next closest electrically connected" and how? In order to make this determination, a certain amount of knowledge about the other entity's infrastructure is required.

Of even greater concern is the continued inclusion of data from unregistered entities despite the open acknowledgment by the SDT of the challenges with collecting said data (see Technical Rationale, paragraph 2). We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved and can be included in the next draft of MOD-032-2.

Additionally ACES collected the following comments for the consideration of the SDT:

1. "Once the GO-IBR standards are in place, the DP should not be part of this equation at all. This is especially true of non-registered members. Put the burden onto the GO-IBR not the DP."

2. "The latest draft of MOD-032 no longer requires reactive power information to be collected for DERs. While most smaller systems really only operate at unity, it is the belief of NCEMC having this information will allow planners to more accurately model Distributed Energy Resources, thereby improving grid reliability. Thus, NCEMC recommends that reactive power data collection for DERs be required by MOD-032."

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
6D: issues with "next electrically closest" - need clarification
Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale.

6E: GO-IBR to the rescue (related to theme 1D)
The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

2C: elimination of reactive power
The DT removed the reactive power capability in response to previous industry comments. A DER's reactive power operating characteristics can depend on many factors aside from the maximum capability, including the mode of reactive power control. For instance, if the DER is in

volt/var control mode, the distribution system loading, voltage regulation scheme, and impedance can all affect the DER's reactive power output. The Attachment 1 information provides a minimum baseline for information. The PC/TP may request additional information to make assumptions about aggregate DER reactive power operating characteristics.	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	
Document Name	
Comment	
The SDT should give consideration to paragraph 105 of FERC Order No. 901 which states that if distribution providers are unable to gather adequate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. Southern supports the comments by EEI on potential implementation challenges.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI. 6B: FERC 901 reference to allow estimated data Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale.	
Kinte Whitehead - Exelon - 3	
Answer	
Document Name	

Comment
Exelon concurs with the comments submitted by the EEI. Exelon suggests the drafting team consider allowing TP/PCs to establish a threshold for aggregate DER reporting. Certain types of DERs such as non-exporting, or DERs connected behind the meter as load offsetting DERs may not be of concern to the TP/PC should be exempt from DP/TO data collection and reporting requirements. Data collection and reporting requirements should focus on "front of meter" connected DERs who primarily export energy, or DERs participating in wholesale markets. Additionally, FERC Order 2222 will require some level of DER data reporting and modeling that may result in the proposed changes to MOD-032 becoming duplicative of, and in some cases in conflict with, obligations imposed by Order 2222.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. See response to EEI. 6N: Threshold needed - PC/TP discretion? (related to themes 1C, 2D and 3C) The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable. 6O: FERC 2222 coordination FERC 2222 may provide a different avenue for PC/TP obtaining needed data - care will be needed to not double count if that avenue is used (and PC/TP may need to adjust their data reporting requirements), but it's not clear how MOD-032-2 would conflict. The Technical Rationale already includes statements acknowledging these types of scenarios.

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 2

Answer	
Document Name	2022-02 Unofficial_Comment_Form_SRC_11-20-23_FINAL_as filed.docx

Comment

The SRC offers the following additional comments and recommendations:

Ensure consistency between Attachment 1, footnote 5 and steady-state item 9: The SRC is concerned that steady-state item 9 in Attachment 1 may not be consistent with footnote 5. Item 9 addresses instances in which DER is directly connected to a TO or DP, while footnote 5 addresses instances in which DER is not directly connected to a NERC-registered entity. Rather than addressing these topics in two separate locations, the SRC recommends that the drafting team ensure consistent language is used to describe each topic and consider addressing both topics in the same location, such as by moving relevant language from item 9 down to footnote 5.

The SRC recommends the SDT review and standardize its use of "DER" throughout the document. For example, MOD-032-2, Attachment 1, item 9 states:

Distributed Energy Resource (DER) data4 [DP, TO where DER is directly connected to the TO system and not through a DP (when DER is not associated with a registered DP)]5

However, this description of DER as "*DER is directly connected to the TO system and not through a DP*" appears to conflict with the DER definition (on page 2) which states: "*Generators and energy storage technologies connected to the Distribution Provider's system…*" To the extent a TO can also serve as a Distribution Provider and a DER is connected to the DP portion of a TO's system, there is no need to refer to that entity as a "TO" as the standard would apply to them as a DP.

Alternatively, if DERs can also be directly connected to a TO system, then the Distributed Energy Resource (DER) definition needs to be updated to reflect that as detailed below:

Generators and energy storage technologies connected to ***either a Transmission Owner's system or a*** *Distribution Provider's system that are capable of providing Real Power in non-isolated parallel operation with the Bulk Electric System.*

· Distribution Provider refers to the NERC glossary definition, not the NERC registered entity.

Stay within NERC's purview and require NERC-registered entities to provide DER information: To keep this project moving forward, the SRC recommends the SDT maintain its scope within NERC's regulatory purview. Requiring NERC registered entities to request information from non-registered entities as in Attachment 1, Footnote 5, moves the burden from entities that own and control the data to entities who do not own or control DER data. Entities are free to request information at any time without a standard. Using a mandatory standard to require an entity to request data is of little to no value. **The benefit of a mandatory standard lies in placing a requirement on the appropriate entity to provide the data**. Without a requirement on the providing entity, the data collected may be garbage and lead to poor modeling results; i.e. garbage in/garbage out.

As DERs proliferate, this increases the risk, administrative burden and cost on registered entities to expend time and energy on requesting and passing through DER data from unregistered entities that have no obligation to provide it ("pull" method). As non-registered entities have no obligation to provide the data or ensure its quality, this process may translate into a costly proposition that leads to poor modeling results. If the goal is to obtain quality data for modeling, NERC must ensure that it has the appropriate registration criteria and rules in place to require applicable NERC registered entities to provide it ("push" method) to modeling entities.

Footnote 5: *Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.*

Review the adequacy of Distribution Provider registration criteria. As noted in the **Technical Rationale for Reliability Standard MOD-032-2** and in Attachment 1, Footnote 5, the SRC observes that in some cases, the entity that owns and controls the DER information may not be a NERC-registered DP. In fact, in July 2018 NERC relaxed its Distribution Provider registration criteria which allowed certain entities to deregister as Distribution Providers,[1] thereby removing what would otherwise have been in place to compel a broader scope of entities to provide DER data.

To that end, NERC has the obligation to ensure all Distribution Providers with the ability to impact the reliability of the BES are registered. Therefore, NERC should verify whether its existing DP registration criteria is adequate to ensure reliable modeling. As with the registration of IBRs (where the approach proposed under Docket RD22-24-000 is expected to result in approximately 98% of BPS-connected IBR nameplate capacity being subject to applicable NERC Reliability Standards), existing DP registration requirements should likewise be made adequate to acquire needed DER information.

Although NERC may not be able to address this now, NERC should nonetheless commit to a plan to perform this validation as it would be helpful to know whether the existing registration criteria for a "Distribution Provider" is sufficient to capture a predominance of DERs. If not,

NERC could develop and implement a plan to register DPs that would close the gap. In this way, this effort will not delay the SDT from moving forward with proposed modifications to MOD-032-2 now, as acquiring some DER information now will provide substantial improvement in PC and TP studies.

Standardize the required level of aggregation: The SRC is concerned if the standard does not specify or standardize "the required level of aggregation" among PC/TPs. The reason for this is to ensure future compliance audits will have an established aggregation level and removes any ambiguity of "the required level of aggregation" between the PC/TP being audited and the auditor.

Footnote 4 "*The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and* ***the required level of aggregation****. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.*"

Ensure comprehensive reporting: The SRC is concerned with the proposed written language as it allows a gap as to knowing whether or not the registered DP or non-registered DP is providing all information and data – leaving an unknown compliance responsibility. This is especially true for non-jurisdictional entities, where the data may be unverifiable (un-auditable) and would lead to additional compliance concerns. One possible remedy is to aggregate small generators of the same type, along with an optional MW threshold for reporting.

[1] **ERO Enterprise Registration Practice Guide:** Distribution Provider "directly connected" Determinations Version 2: July 5, 2018

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
6I: Separate registration for TO with DER?/clarify TO obligation & FN5
Footnotes 4 and 5 were combined and modified to add clarity and a more detailed description of the DT intent was added to the Technical Rationale.

3B: Data accuracy
It is understood that modeling aggregate DER (based on collected data) will involve some assumptions (similar to modeling aggregate load response). The work of the SPIDERWG provides technical references and industry best practices: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

The DP registration suggestion is aligned with DT statement in the Technical Rationale.

Related to 6S: standardized aggregation
The intent is not to require a detailed model for every single DER and the DT is not proposing any such requirement. However, DER data items proposed to be added to Attachment 1 are needed to assess the reliability impact of aggregate DER in system studies. Across the continent, there are variations of DER penetrations and preponderance of DER classes (some areas may have more residential rooftop solar, others may have more utility scale DER). Therefore, it is prudent to allow the PC/TP greater flexibility in determining the details regarding DER data requirements rather than being overly prescriptive in MOD-032. "Aggregate" was added to the DER data item in Attachment 1 to clarify the information that is expected to be included in the transmission model.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

In Attachment 1 please capitalize “interconnection-wide” in the following sentence: “Data must be shareable on an **interconnection-wide** basis to support use in the **Interconnection-wide** cases.”

Did the SDT intend to have the TO(s) gather Item 1 in the “short circuit” column of the table in Attachment 1 for DERs (Item 9 in “steady-state” column)?

Has the SDT collaborated with Project 2022-04 EMT Modeling SAR team on any possible changes to MOD-032 that could be promoted now versus waiting to re-open MOD-032?

Attachment 1 Footnote 5- Determining the “next closest electrically connected entity” is very broad and subject to interpretation especially if deep within multiple jurisdictions (TO and DP or multiples of each). What mechanism is in place for registered DPs and TOs to ensure that

data is collected appropriately for a non-registered DP? "Appropriately" may mean avoiding a couple of scenarios---Accounted for twice or more (once by a TO AND once or more by one or more registered DPs) or not accounted for at all by either the DP or TO. Is the SDT leaving the determination of "next closest electrically connected entities" to the TP or PC?

Additionally, would recommend a footnote 5 (or 6) be added to Item 10 in the "dynamics" column to provide clarity versus referring to item 10 within the footnote itself.

For Item 9 in "steady-state" column (i.e., DER data). WECC would suggest changing "Generator type (solar, battery, etc.)" to be more reflective of the proposed definition of DER which starts out as "Generators and energy storage technologies…". Consider removing "Generator" from 9c and simply say "Type (solar, battery, etc.)"

The SDT should consider utilizing or correcting Glossary of Term usage within Table 1 to reflect "Real Power" and "Reactive Power" for all parts of the table to provide clarity.

Further comments for Question 1: The addition of the phrase "Distribution Provider refers to the NERC glossary definition, not the NERC registered entity" may cause confusion as the ROP definition of the registered entity (DP) is the same as the Glossary of Terms. SDT should further consider if a different term should be utilized to avoid some confusion. WECC appreciates the idea of trying to illustrate what the entity functions may be regardless of the determination for registration (and the ensuing obligation to NERC Reliability Standards construct if registered.)

ROP definition in Appendix 5b: "Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."

ROP definition in Appendix 2:" "Distribution Provider" means the entity that provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**"

Glossary of Terms Definition: "Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
Interconnection is defined in the NERC glossary as:
“A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.”

The DT believes that the use of non-capitalized “interconnection-wide” within MOD-032-1 may have been intentional; no change made.

Explicitly adding DER data to the "short circuit" column was outside the scope of this SAR. As noted in the Technical Rationale, the PC or TP is not restricted from requiring any needed short circuit data in their joint modeling data requirements and reporting procedures developed per R1.

The DT is aware of Project 2022-04. EMT model requirements are beyond the scope of this SAR. Ultimately, the Project 2022-04 team may propose EMT model data collection requirements. At this time, it is not clear that MOD-032 is an appropriate location for such requirements.

6D: issues with "next electrically closest" - need clarification
Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale.

6P & 6Q: dynamics 10/steady state 9
DT addressed the issue with referring to Item 10 for dynamics within the footnote for item 9 in steady state.
Steady state Item 9 was modified to address the concern.

6R: Modify to Real/Reactive defined terms throughout?
Addressing the use of defined terms for Real Power and Reactive Power throughout MOD-032 is beyond the scope of this SAR. The DT believes that the usage of capitalized or non-capitalized terms may have been intentional.

1G: Confusion between glossary DP and registered DP The DT found that the confusion related to the NERC glossary definition for Distribution Provider and the NERC registration criteria was pre-existing. The DT attempted to clarify that use of "Distribution Provider" in the proposed DER definition is not referring to NERC registration. The use of the "Distribution Provider" within the standard without further specific explanation refers to the NERC registered entity. The DT added language in the Technical Rationale and also modified the proposed definition to clarify.
Carly Miller - Carly Miller On Behalf of: Micah Runner, Black Hills Corporation, 5, 6, 1, 3; - Carly Miller

Answer	
Document Name	

Comment
Black Hills Corporation agrees with other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.
Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

Black Hills Corporation agrees with other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
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 other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	

Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	

Exelon concurs with the comments submitted by the EEI.

Exelon suggests the drafting team consider allowing TP/PCs to establish a threshold for aggregate DER reporting. Certain types of DERs such as non-exporting, or DERs connected behind the meter as load offsetting DERs may not be of concern to the TP/PC should be exempt from DP/TO data collection and reporting requirements. Data collection and reporting requirements should focus on "front of meter" connected DERs who primarily export energy, or DERs participating in wholesale markets.

Additionally, FERC Order 2222 will require some level of DER data reporting and modeling that may result in the proposed changes to MOD-032 becoming duplicative of, and in some cases in conflict with, obligations imposed by Order 2222.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. See response to EEI.

6N: Threshold needed - PC/TP discretion? (related to themes 1C, 2D and 3C)
The DT consensus is that it is most appropriate to not include a threshold within the DER definition. NERC has recommended a zero MVA threshold for gathering DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf
It is expected that PC/TP procedures may specify thresholds and technical justification for inclusion of DER models (or not) in any particular study – this issue is more aligned with the SAR for TPL-001 that will be addressed in the second phase of this project 2022-02. A single threshold is not likely universally applicable.

6O: FERC 2222 coordination

FERC 2222 may provide a different avenue for PC/TP obtaining needed data - care will be needed to not double count if that avenue is used (and PC/TP may need to adjust their data reporting requirements), but it's not clear how MOD-032-2 would conflict. The Technical Rationale already includes statements acknowledging these types of scenarios.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with other entities that Footnote 5 should be deleted. The "next closest electrically connected registered entity" DP, TO, or PC to an unregistered distribution provider, should not be held responsible for providing DER data outside of their control or ability to collect.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
Ben Hammer - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
Transmission Owners who are not Distribution Providers likely have no knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. Transmission Owner visibility for load demand is typically limited to historical telemetered MW and MVAR data. This finding, especially with regards to DERs, has already been well-documented. A key recommendation in the NERC Reliability and Security Technical Committee (RSTC) subcommittee approved the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was:	

"TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements or practices that will ensure this data is available. ***As the TPs, PCs, and TOs are dependent on the DP to have the data made available****, this will likely require actions from state regulatory bodies and DPs to establish requirements to gather this information" (page 7 of 61).*

The SDT should consider that Transmission Owners should not be held accountable for demand and DER data that they have no cognizance of. Additionally, the SDT should remember that most DER are smaller than the BES resource threshold or reside on a distribution system. The threshold for an entity to be registered as a Distribution Provider is 75 MW of load. This implies that the majority of DERs are and will be connected to systems outside the scope and visibility of Transmission Owners, as well as existing Distribution Providers. To emphasize this reality: as of 15 May 2023, there were 314 Distribution Providers registered with NERC (excluding UFLS-only DPs). Of those DPs, 96 were not otherwise registered as either a PC, TP, or TO. While it may be misunderstood that only 96 DPs may become newly applicable and participatory in model data collection given the draft changes to MOD-032-2, this ignores that the latest EIA 861 data (collected in 2021; published in 2022) reflects about 1,190 distribution utilities reflecting almost 197,000 distribution circuits in the continental US. In other words, it may be reasonable to conclude that 74% of the distribution utilities in the US do not meet the NERC registration threshold. Furthermore, PCs, TPs, and TOs have no regulatory relationship with these unregistered entities and cannot be held responsible for DER data for which that are not aware.

In June 2022, NERC published its "Inverter-Based Resource Strategy" that recognized efforts necessary to analyze the breakdown of resource size, location, type, and applicability with the BES definition to make a determination of whether the current BES threshold should be updated to reflect the changing resource mix" (page 9 of 10). Subsequently, the NERC Member Representatives Committee (MRC) and Board of Trustees (BOT) technical session on inverter-based resources in February 2023 emphasized the need for a focus on functional registration noting: "industry is increasingly challenged with addressing reliability issues for unregistered inverter-based resources, and those resources are reaching critical mass in some parts of the country. The lack of requirements currently imposed on those resources creates local and regional reliability risks to the BPS in aggregate. This issue compounds in many areas with the growing presence of distributed energy resources (DERs) connected to the distribution system." In response to the FERC directive "Registration of Inverter-based Resources", NERC filed a proposal to modify its Rules of Procedure to "include a new function comprised of owners of IBRs interconnected to the BPS." The Generator Owner – Inverter-Based Resource (GO-IBR) registration would include "owners of IBRs which have aggregate nameplate capacity of less than or equal to 75 MVA and greater than or equal to 20 MVA interconnected at a voltage greater than or equal to 100 kV; or Owners of IBRs which have aggregate nameplate capacity of greater than or equal to 20 MVA interconnected at a voltage less than 100 kV."

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent. 6E: GO-IBR to the rescue (related to theme 1D) The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.	
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.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	

Document Name	
Comment	
The NAGF suggests that NERC consider the work being performed under Project 2023-05 to revise FAC-001 – Facility Interconnection Requirements to include Distribution Provider which may help to alleviate the drafting team's concerns regarding the ability of either TO or DP needing to obtain data from unregistered entities that own DERs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. At the time of this response, the 2023-05 team does not appear to have been formed yet, but this comment supports the idea that DPs and TOs should have the necessary DER data.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
Attachment 1 Data Reporting table (Steady State Column items 2, and 9, and Dynamics Column items 5, and 10) has added language indicating that the Transmission Owner (TO) is the responsible entity for submitting modeling data when a demand is not associated with a registered Distribution Provider. AZPS requests clarification regarding the type of entity that would have load, but not be a registered distribution provider. AZPS is concerned that the Transmission Owner may not have the ability to produce or acquire certain load information from an unregistered entity unless there is some other type of contractual relationship in place.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

This comment appears applicable to draft 1 rather than draft 2, but the DT believes that the expressed concerns have been addressed. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
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	
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) and MRO NSRF for question #6.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. See responses to EEI and MRO NSRF.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
In Attachment 1, Item 9, Texas RE recommends the SDT consider not removing the minimum and maximum for Real Power capability and Reactive Power capability (minimum and maximum) for DER data requirements. If the minimum and maximum Real Power and Reactive Power data is available, it should be submitted the TP/PC to be included in the system model which will yield more accurate models that are represented in Real-Time operations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. MOD-032 should establish minimum requirements across the continent without being overly prescriptive. The PC/TP can require additional or more detailed information per Requirement R1, but at a minimum Real Power capability must be included in their data requirements and reporting procedures.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
Very little has changed from Draft 1 to Draft 2 of the proposed modifications to MOD-032-2. ATC supports the comments from the MRO-NSRF.	

In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry consideration. A separate effort should be initiated to explore making DER entities above a specified threshold a NERC registered entity to ensure data will be correctly shared. The DT may also consider waiting until possible modifications have been suggested to MOD-032 in response to FERC Order No. 901 and IBR modeling.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to MRO NSRF. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such Footnotes, 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent. 6T: Prioritize administrative issues with MOD-032/Wait for 901 The DT does not believe that the development of essential requirements related to ensuring appropriate DER data is available to PCs and TPs should be delayed to put the industry behind the curve as they are with IBR performance requirements. The DT believes this is aligned with the urgency conveyed in FERC Order No. 901.	
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	

While these modifications are necessary, approving them prior to the DT's documented concerns over the changes to the DP registration creates a disconnect that has the potential for unintended future consequences. SRP recommend the DT crate a SAR for adjusting the definition of DP to include the DER resources prior to moving forward with this effort.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
6J: Don't move forward without addressing registration gap
The DT believes that the data collection covered by the current registration available covers a significant portion of the DER data and provides a reliability benefit prior to efforts to close the registration gap and collect the remaining DER data.

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name
SPP RTO

Answer	
Document Name	

Comment

SPP recommends this drafting team coordinates with the Project 2023-08 drafting team to ensure the appropriate DER data is identified as well as listed to meet the needs of the two standards from an efficient and reliability prospective.

Furthermore, we recommend that the drafting team consider creating an independent registration for the TO with direct connection to DERs (R-DERs). From our perspective, the proposed Attachment 1 (footnotes) does not clearly define the role for this particular Transmission Owner (TO). Moreover, the independent document can be used to provide clarity on the expectation of the role for the TO with direct connection to DERs (R-DERs).

In support of the proposed solution, we recommend that the drafting team review the efforts made in the NERC Rules of Procedures (RoP) in reference to the GO (IBR) and GOP (IBR) pertaining to their definition and registration.

Additionally, we recommend that the drafting team takes into consideration the impact of creating a separate project to address the proposed definition in an independent process. We have the concern that the creation of an independent project for the definition will only delay the efforts of addressing the needs for DER data collection. From our perspective, the definition effort needs to be finalized before pursuing other activities associate with data collection. Finally, SPP recognizes that DPs and TOs have expressed concern with their ability to obtain granular DER data and because of this, the proposed data collection modifications to MOD-032-2 may not be accepted by industry. To help reach consensus, SPP suggests that the drafting team consider an alternative mechanism that would allow the DPs and TOs to forecast DER data based on their knowledge of DER penetration on their systems, especially when the data is not directly available through a NERC standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. At the time of this response, the 2023-08 team has not been formed yet - that SAR was also initiated at SPIDERWG, so the DT does not expect conflicts in objectives.

6I: Separate registration for TO with DER?/clarify TO obligation & FN5
Footnotes 4 and 5 were combined and modified to add clarity and a more detailed description of the DT intent was added to the Technical Rationale.

6E: GO-IBR to the rescue (related to theme 1D)
The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.

1A: DT should not define DER - separate project needed

The SC approved the DT and the SAR which includes consideration of a DER definition in its scope. The DT considered a range of existing DER definitions with broad applicability across electric system planning and operations in proposing the current version; it is not intended to be specific to MOD-032. The DT recognizes the wide-reaching impacts of this definition. 3B: Data accuracy It is understood that modeling aggregate DER (based on collected data) will involve some assumptions (similar to modeling aggregate load response). The work of the SPIDERWG provides technical references and industry best practices: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute for Duke Energy's official response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to EEI.	
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	
Thank you for your comments. See response to MRO NSRF.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
MPC supports comments submitted by ACES and the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to ACES and MRO NSRF.	
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 for your comments. See response to EEI.	

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 respectfully abstains from this ballot event and recommends NERC staff, the Standards Committee, and the Standards Drafting Team revisit the project scope in light of the directives in FERC Order 901, issued October 19th, 2023.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 6T: Prioritize administrative issues with MOD-032/Wait for 901 The DT does not believe that the development of essential requirements related to ensuring appropriate DER data is available to PCs and TPs should be delayed to put the industry behind the curve as they are with IBR performance requirements. The DT believes this is aligned with the urgency conveyed in FERC Order No. 901.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
AES Clean Energy believes that the new requirements for DERs will help TPs and PCs to better understand the root cause of system instability. However, there is still concern about the ability of the TO and DP to obtain the data from unregistered entities that own the DERs. Currently, FAC-001 allows the TO to specify its interconnection requirements which may help TO to obtain the necessary data. However, there is no similar requirement for DP. AES Clean Energy recommends the Standard Drafting Team to look into this as well.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT doesn't envision a need to request detailed technical information directly from customers. The DT contends that DPs should already have a record and basic understanding of DER that is connected to their system (e.g., rooftop solar, batteries, etc.) similar to how they have a record and basic understanding of houses, factories, and commercial spaces connected to their system. Such information should be sufficient for PCs an TPs to properly represent potential DER reliability impacts.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource recommends either Footnote 5 or the requirements be modified to make clear that the next closest DP or TO to an unregistered distribution provider should not be held responsible for providing DER data in case the unregistered entity does not supply this information, but only responsible to request this data. If the unregistered distribution provider does not supply this information, the DP or TO should remain compliant as long as they submitted the request.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	

Document Name	
Comment	
Buckeye Power, Inc. supports the comments of ACES: We have a great deal of apprehension as it relates to proposed language in Footnote 5 of Attachment 1. Footnote 5 states (emphasis added): "Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column." By what method should it be determined which registered entity is the "next closest electrically connected". Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the "next closest electrically connected" and how? In order to make this determination, a certain amount of knowledge about the other entity's infrastructure is required. Of even greater concern is the continued inclusion of data from unregistered entities despite the open acknowledgment by the SDT of the challenges with collecting said data (see Technical Rationale, paragraph 2). We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved and can be included in the next draft of MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See response to ACES.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
Transmission Owner is not listed as a Functional Entity to which the proposed standard(s) should apply in the SAR. The SAR states that the Functional Entities to which the proposed standard(s) should apply are the Transmission Planner (TP), the Planning Coordinator (PC) and the	

Distribution Provider (DP). This section of the SAR is designed to, “assist the NERC Standards Committee in appointing a drafting team with the appropriate members.” The proposed language in ATTACHMENT 1, affects and changes the obligations of the Transmission Owner (TO). Changes to the obligations of the Transmission Owner (TO) were not approved in the SAR and SDT members selected may not provide adequate representation of TOs.

In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry consideration. NV ENERGY recommends that the Standard Drafting Team consider utilizing the procedures allowed for by NERC Rules of Procedure to halt activity on this project until such time that issues surrounding data collection from entities who have no obligation to comply are addressed.

NV Energy has concerns with Footnote 5 of Attachment 1:

“Where DER is connected to an unregistered Distribution Provider, the **next closest electrically connected** registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the “dynamics” column.”

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
6C: TO was not identified on SAR/TO representation is lacking on DT
TOs are represented on the DT and changes made to the Table in Attachment 1 and Footnotes 4 and 5 should address TO concerns.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity

The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent. 6D: issues with "next electrically closest" - need clarification Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale.	
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	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	

There needs to be a way to exempt or use generic models for legacy systems. Additionally, with some state regulators, such as the MPSC, it may be difficult to request information from customers that are not within the MPSC procedures and rules.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT contends that DPs should already have a record and basic understanding of DER that is connected to their system (e.g., rooftop solar, batteries, etc.) similar to how they have a record and basic understanding of houses, factories, and commercial spaces connected to their system. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. MOD-032-2 highlights PC/TP flexibility in developing data requirements and reporting procedures in both Footnote 2 and Footnote 4.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
- Currently, the existing U-DERs are not obligated to provide any data for models. It may not be a problem for new U-DERs since data requirement can be incorporated in the IOA. - It is more appropriate to list the item 9.d in steady-state modelling requirement under dynamic modelling data requirements. (d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.)	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The DT contends that DPs should already have a record and basic understanding of DER that is connected to their system (e.g., rooftop solar, batteries, etc.) similar to how they have a record and basic understanding of houses, factories, and commercial spaces connected to their system. However, as suggested, there may be additional opportunities to obtain data for U-DER. Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale. 6G: Move control capabilities to dynamics? As noted in the Technical Rationale, the DT maintained the approach from MOD-032-1 where detailed sub-bullets are only presented in the "steady state" column although such information may also be relevant to "dynamics" or "short circuit." In general, information about control and ride-through capabilities could be used to inform steady state behavior assumptions.
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment
Transmission Owner is not listed as a Functional Entity to which the proposed standard(s) should apply in the SAR. The SAR states that the Functional Entities to which the proposed standard(s) should apply are the Transmission Planner (TP), the Planning Coordinator (PC) and the Distribution Provider (DP). This section of the SAR is designed to, "assist the NERC Standards Committee in appointing a drafting team with the appropriate members." The proposed language in ATTACHMENT 1, affects and changes the obligations of the Transmission Owner (TO). Changes to the obligations of the Transmission Owner (TO) were not approved in the SAR and SDT members selected may not provide adequate representation of TOs. In the Technical Rationale, the Standard Drafting Team acknowledges that there may be challenges in collecting data for DER connected to unregistered entities and that the obligations of this standard may place an unreasonable compliance risk on registered entities. However, despite the acknowledgement of this unreasonable risk, the Standard Drafting Team has put forth in draft 2 similar language, containing the same unreasonable risk for industry consideration. MRO NSRF recommends that the Standard Drafting Team consider utilizing the procedures

allowed for by NERC Rules of Procedure to halt activity on this project until such time that issues surrounding data collection from entities who have no obligation to comply are addressed.

The NSRF has concerns with Footnote 5 of Attachment 1:

"Where DER is connected to an unregistered Distribution Provider, the **next closest electrically connected** registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column."

By what method should it be determined which registered entity is the "next closest electrically connected?" Consider the case wherein a substation owned by an unregistered DP has a feeder from 2 different registered entities. Who is to make the determination as to which registered entity is the "next closest electrically connected" and how? In order to make this determination, a certain amount of knowledge about the other entity's infrastructure is required.

In closing, the NSRF would like to reemphasize the significant challenges in collecting the data in question from non-NERC-registered entities, challenges that the SDT itself has acknowledged (see Technical Rationale, paragraph 2).We recommend that the SDT postpone further development of this Project until the GO-IBR and GOP-IBR registration criteria have been approved.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Thank you for your comments.
6C: TO was not identified on SAR/TO representation is lacking on DT
TOs are represented on the DT and changes made to the table in Attachment 1 and Footnotes 4 and 5 should address TO concerns.

2AG: Still maintains unreasonable compliance obligations + FN 5 - explain intent if no response from unregistered entity
The DT recognized the need for clarity in Footnote 5. As such, Footnotes 4 and 5 were modified and combined to address unreasonable compliance obligations. The Technical Rationale was also updated to clarify the DT intent.

6D: issues with "next electrically closest" - need clarification Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale. 6E: GO-IBR to the rescue (related to theme 1D) The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e. greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
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 of both EEI and the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. See responses to EEI and MOR NSRF.	
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	
Industry might be more open to language that mimics FERC Order 901, Paragraph 141, for Verification of IBR Plant Dynamic Model Performance. The requirements could be modified to allow the Transmission Owner and/or Distribution Providers, if unable to gather accurate DER data, or unable to gather DER data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of individual DERs and DERs in the aggregate using ***estimated data***. This would give the Planning Coordinators the latitude to use their best judgement and experience in developing the most accurate models for their areas if they cannot get the data from the DER owners or “unregistered Distribution Providers”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 6B: FERC 901 reference to allow estimated data	

Consistent with what is described in FERC Order No. 901 and what already takes place with load demand, some level of estimation is anticipated as described in the Technical Rationale.	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
No TPL questions?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The modifications to TPL-001 will be proposed in the second phase of project 2022-02. The SDT concluded that it was necessary to complete the DER definition and data obligations in MOD-032 prior to working on TPL study requirements associated with DER.	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	
Document Name	
Comment	
In Attachment 1, the steady state section 2 removed the TO due to the DP NERC glossary definition. I think the TO should also be removed from steady state section 9 and dynamics section 10 for the same reason.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The TO is referenced in the footnote related to item 2 and was similarly added to the footnote related to Item 9. The DT contends that the TO may have a role in reporting both load data and DER data.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy believes Footnote 5 should be deleted. The next closest DP or TO to an unregistered distribution provider should not be held responsible for providing DER data outside of their control or ability to collect. Further, FirstEnergy supports EEI's comments which state: EEI notes that this project has been listed as a low priority project. While we understand this may have some immediate impacts on the work being conducted by this SDT, we suggest that a two phased approach for the revision of MOD-032 might address the immediate concerns surrounding efforts to align registration under Project 2017-02. Phase 1: Consider completing the work from project 2017-02 Standards Alignment with Registration: Replace Load-Serving Entity (LSE) with Distribution Provider (DP), remove the Planning Authority (PA) functional entity name and keep the Planning Coordinator (PC) functional entity name, and make the associated LSE / DP functional changes to the standard requirements. Phase 2: Please consider addressing additional DER data requirements, after further discussion regarding how GO-IBR and GOP-IBR standards are going to be addressed and what is needed from Distribution Providers regarding unregistered IBRs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 6D: issues with "next electrically closest" - need clarification Footnotes 4 and 5 were combined and modified to eliminate the “next closest electrically connected” language and add clarity. A more detailed description of the DT intent was added to the Technical Rationale.	

6T: Prioritize administrative issues with MOD-032/Wait for 901
The DT does not believe that the development of essential requirements related to ensuring appropriate DER data is available to PCs and TPs should be delayed to put the industry behind the curve as they are with IBR performance requirements. The DT believes this is aligned with the urgency conveyed in FERC Order No. 901.

6E: GO-IBR to the rescue (related to theme 1D)
The proposed GO-IBR registration effort is primarily intended to capture the smaller transmission-connected resources that don't meet BES definition. Most individual DER will not meet proposed GO-IBR registration criteria (i.e., greater than 20 MVA) so that effort will provide little benefit with respect to making DER data available to PC/TPs. Yet, smaller individual DER installations connected to DP systems can, in aggregate, have a significant impact on BES reliability.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder
Standards Announcement
Project 2022-02 Modifications to TPL-001 and MOD-032

Additional Ballots and Non-binding Poll Open through November 20, 2023

Now Available

Additional ballots and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be open **Friday, November 10, 2023** through **8 p.m. Eastern, Monday, November 20, 2023** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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 2022-02 Modifications to TPL-001 and MOD-032 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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Modifications to TPL-001 and MOD-032

Formal Comment Period Open through November 20, 2023

Now Available

A formal comment period for **Project 2022-02 Modifications to TPL-001 and MOD-032** is open through **8 p.m. Eastern, Monday, November 20, 2023** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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 standard and implementation plan, as well as the non-binding poll of the

associated Violation Risk Factors and Violation Severity Levels will be conducted **November 10 – 20, 2023**.

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 2022-02 Modifications to TPL-001 and MOD-032 observer list” in the Description Box.

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 AB 2 ST
Voting Start Date: 11/10/2023 12:01:00 AM
Voting End Date: 11/20/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 249
Total Ballot Pool: 292
Quorum: 85.27
Quorum Established Date: 11/20/2023 3:10:51 PM
Weighted Segment Value: 39.52

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	79	1	19	0.339	37	0.661	1	8	14
Segment: 2	7	0.7	5	0.5	2	0.2	0	0	0
Segment: 3	65	1	17	0.34	33	0.66	0	6	9
Segment: 4	15	0.9	3	0.3	6	0.6	0	2	4
Segment: 5	74	1	18	0.327	37	0.673	0	9	10
Segment: 6	44	1	9	0.265	25	0.735	0	5	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.4	3	0.3	1	0.1	0	2	1
Totals:	292	6	74	2.371	141	3.629	1	33	43

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments

					Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright	Jennifer Lapaix	Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
1	Santee Cooper	Chris Wagner		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Santee Cooper	Vicky Budreau		None	N/A

6	Santee Cooper	Marty Watson		None	N/A
5	Santee Cooper	Carey Salisbury		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Negative	Third-Party Comments
5	Tennessee Valley Authority	Nehtisha Rollis		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Negative	Third-Party Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Salt River Project	Mathew Weber		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments

1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Affirmative	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
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted

3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
1	Duke Energy	Katherine Street		None	N/A
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted

3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Salt River Project	Sarah Blankenship		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments Submitted
3	AEP	Kent Feliks		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments

1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Abstain	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	SaskPower	Wayne Guttormson		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
					Third-Party

1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Comments Submitted
10	New York State Reliability Council	Wesley Yeomans		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Abstain	N/A
1	Entergy	Brian Lindsey	Kristen Long	Negative	Comments Submitted
4	Electricities of North Carolina	Marcus Freeman		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Abstain	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A

3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party

					Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Negative	No Comment Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Comments Submitted
3	BC Hydro and Power Authority	Alan Xu		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A

6	Western Area Power Administration	Chrystal Dean	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya	Negative	Third-Party Comments
5	LS Power Development, LLC	C. A. Campbell	Abstain	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan AB 2 OT
Voting Start Date: 11/10/2023 12:01:00 AM
Voting End Date: 11/20/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 246
Total Ballot Pool: 290
Quorum: 84.83
Quorum Established Date: 11/20/2023 3:11:48 PM
Weighted Segment Value: 48.24

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	78	1	22	0.4	33	0.6	1	8	14
Segment: 2	6	0.6	5	0.5	1	0.1	0	0	0
Segment: 3	64	1	20	0.408	29	0.592	0	6	9
Segment: 4	15	0.9	4	0.4	5	0.5	0	2	4
Segment: 5	75	1	23	0.418	32	0.582	0	9	11
Segment: 6	44	1	13	0.371	22	0.629	0	4	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.3	3	0.3	0	0	0	3	1
Totals:	290	5.8	90	2.798	122	3.002	1	33	44

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A

6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright	Jennifer Lapaix	Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
1	Santee Cooper	Chris Wagner		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Santee Cooper	Vicky Budreau		None	N/A
6	Santee Cooper	Marty Watson		None	N/A
5	Santee Cooper	Carey Salisbury		None	N/A

1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Negative	Third-Party Comments
5	Tennessee Valley Authority	Nehtisha Rollis		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Negative	Third-Party Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Salt River Project	Mathew Weber		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A

3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A

3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
1	Duke Energy	Katherine Street		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Negative	Comments Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted

5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Affirmative	N/A
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Salt River Project	Sarah Blankenship		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
6	AEP	Mathew Miller		Negative	Comments Submitted
3	AEP	Kent Feliks		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	Comments Submitted
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted

1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	SaskPower	Wayne Guttormson		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A

5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Abstain	N/A
1	Entergy	Brian Lindsey	Kristen Long	Affirmative	N/A
4	Electricities of North Carolina	Marcus Freeman		None	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Abstain	N/A
3	Entergy	James Keele		Affirmative	N/A
5	Salt River Project	Thomas Johnson		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Abstain	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments

3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	No Comment Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
					Comments

3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	Submitted
3	BC Hydro and Power Authority	Alan Xu		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A



Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 AB 2 NB
Voting Start Date: 11/10/2023 12:01:00 AM
Voting End Date: 11/20/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 231
Total Ballot Pool: 278
Quorum: 83.09
Quorum Established Date: 11/20/2023 3:35:11 PM
Weighted Segment Value: 41.24

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	19	0.388	30	0.612	12	16
Segment: 2	6	0.4	3	0.3	1	0.1	2	0
Segment: 3	60	1	17	0.436	22	0.564	11	10
Segment: 4	14	0.9	3	0.3	6	0.6	2	3
Segment: 5	71	1	18	0.391	28	0.609	15	10
Segment: 6	42	1	10	0.37	17	0.63	8	7
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	7	0.3	3	0.3	0	0	3	1
Totals:	278	5.6	73	2.485	104	3.115	54	47

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	No Comment Submitted
5	AEP	Thomas Foltz		Abstain	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	No Comment Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	No Comment Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	No Comment Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		None	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	No Comment Submitted
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	No Comment Submitted
					No

4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comment Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	No Comment Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	No Comment Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	No Comment Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	No Comment Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	No Comment Submitted
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	No Comment Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	No Comment Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	No Comment Submitted
6	Public Utility District No. 2 of Grant County, Washington	Mike Stussy		None	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright	Jennifer Lapaix	Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	No Comment Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	No Comment Submitted

5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	No Comment Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	No Comment Submitted
1	Santee Cooper	Chris Wagner		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	No Comment Submitted
3	Santee Cooper	Vicky Budreau		None	N/A
6	Santee Cooper	Marty Watson		None	N/A
5	Santee Cooper	Carey Salisbury		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	No Comment Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	No Comment Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	No Comment Submitted
5	New York Power Authority	Zahid Qayyum		Negative	No Comment Submitted
6	Salt River Project	Timothy Singh		Negative	No Comment Submitted
3	New York Power Authority	David Rivera		Negative	No Comment Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	No Comment Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	No Comment Submitted
					No

6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Negative	Comment Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	No Comment Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	No Comment Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	No Comment Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	No Comment Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Salt River Project	Mathew Weber		Negative	No Comment Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	No Comment Submitted
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	No Comment Submitted
1	Exelon	Daniel Gacek		Negative	No Comment Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	No Comment Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	No Comment Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	No Comment Submitted

1	Oncor Electric Delivery	Byron Booker		Negative	No Comment Submitted
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	No Comment Submitted
6	Black Hills Corporation	Claudine Bates		Negative	No Comment Submitted
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	No Comment Submitted
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	No Comment Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	No Comment Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	No Comment Submitted
6	Entergy	Julie Hall		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Anna Salmon		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	No Comment Submitted
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Negative	No Comment Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
					No

6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comment Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
1	Duke Energy	Katherine Street		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Negative	No Comment Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
1	National Grid USA	Michael Jones		Negative	No Comment Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	No Comment Submitted
3	Great River Energy	Michael Brytowski		Negative	No Comment Submitted
6	Duke Energy	John Sturgeon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	No Comment Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Negative	No Comment Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
6	Northern California Power Agency	Dennis Sismaet		Negative	No Comment Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	No Comment Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	No Comment Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
					No

1	Eversource Energy	Joshua London		Negative	Comment Submitted
1	Salt River Project	Sarah Blankenship		Negative	No Comment Submitted
6	Constellation	Kimberly Turco		Negative	No Comment Submitted
5	Constellation	Alison MacKellar		Negative	No Comment Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Negative	No Comment Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	No Comment Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	No Comment Submitted
6	AEP	Mathew Miller		Abstain	N/A
3	AEP	Kent Feliks		Negative	No Comment Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	No Comment Submitted
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Negative	No Comment Submitted
10	ReliabilityFirst	Lindsey Mannion		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	No Comment Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	No Comment Submitted
6	Lakeland Electric	Paul Shipps		Abstain	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A

3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	No Comment Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	No Comment Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	No Comment Submitted
1	Hydro One Networks, Inc.	Emma Halilovic		None	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
1	New York Power Authority	Daniel Valle		Negative	No Comment Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	No Comment Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	No Comment Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
6	New York Power Authority	Shelly Dineen		Negative	No Comment

					Submitted
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Negative	No Comment Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	No Comment Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	No Comment Submitted
3	Evergy	Marcus Moor	Alan Kloster	Negative	No Comment Submitted
3	Lakeland Electric	Steven Marshall		Abstain	N/A
1	Entergy	Brian Lindsey	Kristen Long	Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Abstain	N/A
3	Entergy	James Keele		Affirmative	N/A
5	Salt River Project	Thomas Johnson		Negative	No Comment Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Abstain	N/A
3	Omaha Public Power District	David Heins		Negative	No Comment Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	No Comment Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A

5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	No Comment Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	No Comment Submitted
4	DTE Energy	Patricia Ireland		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		None	N/A
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	No Comment Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Negative	No Comment Submitted
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		None	N/A
3	Black Hills Corporation	Josh Combs		Negative	No Comment Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	No Comment Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	No Comment Submitted

3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	No Comment Submitted
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Negative	No Comment Submitted
3	BC Hydro and Power Authority	Alan Xu		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	No Comment Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	No Comment Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	No Comment Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Negative	No Comment Submitted

6	Xcel Energy, Inc.	Steve Szablya	Negative	No Comment Submitted
5	LS Power Development, LLC	C. A. Campbell	Abstain	N/A

Do not use this form for submitting nominations

Unofficial Nomination Form

Project 2022-02 Uniform Modeling Framework for IBR

Submitting Nominations

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2022-02 Uniform Modeling Framework for IBR** supplemental drafting team members by **8:00 p.m. Eastern, Monday, June 24, 2024.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

General Information

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Laura Anderson (via email), or at 404-782-1870.

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 quality review team experience is beneficial, but not required.

Project Information

Project Purpose

FERC Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements SAR addresses regulatory directives from the NERC Standards Development Work Plan to respond to FERC Order No. 901. This project addresses the need to ensure the usage of a uniform framework for data sharing and model development. This project will also build mechanisms to allow equipment-specific models, if approved and as needed for model quality, to facilitate model changes as a result of the Milestone 2, 3, and 4 directives that evaluate performance of IBR.

This project must ensure modeling revisions from other IBR performance requirements in other 901-related projects will utilize the uniform framework. The drafting team will develop requirements for data aggregation estimation and data sharing of aggregated data for generation resources not registered by NERC Assets to be included as part of the revisions to the Compliance Registry criteria (“category 2 type assets”) are considered ”registered IBR” and not subject to the project objectives related to aggregated data or estimation methods.

NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.

Standards Affected

- MOD-032
- TOP-003
- IRO-010

Nominee Expertise Requested

For this project, NERC is seeking individuals who possess experience in one or more of the following areas:

- Generation and Transmission Owners of Inverter-Based Resources;
- Generation and Transmission modeling development;
- Planning and Reliability Coordination of protection and controller settings;
- Transmission Planning;
- Balancing Authorities;
- Distribution Providers;
- Familiarity with NERC Standards MOD-032, TOP-003, and IRO-010; and
- Other tasks for identifying, analyzing, and mitigating reliability issues for BES Inverter-Based Resources.

Time Commitment Expectations

Time commitments for most projects include up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed. Team members may agree to individual or subgroup assignments, to work in separate meetings and present to the larger team for discussion and review. Another important component of quality reviews and drafting team efforts is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Project Priority

Each project will be developed according to that project's priority status. While each standard project addresses particular industry needs, some projects will be identified as a higher priority project. A higher priority project may initially include a strict timeline, which may be needed to effectively respond to a FERC Directive or as determined by the NERC Board of Trustees. A higher priority project may also need to increase the frequency of meetings at any time throughout the development process to account for project timeline needs. Similarly, other priority projects may adjust to a lower frequency of meetings throughout the development process to reallocate resources to high priority projects.

This project has been identified as higher priority at this time. The project has a FERC deadline of November 4, 2025. To meet this deadline, the team will meet regularly, up to three times a week on conference calls, with face-to-face meetings scheduled as the members' schedule allows, up to twice a quarter.

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 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	

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

Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Nomination Period Open through June 24, 2024

Now Available

Nominations are being sought for supplemental drafting team members through **8 p.m. Eastern, Monday, June 24, 2024**.

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.

Time commitments for most projects include up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed. Team members may agree to individual or subgroup assignments, to work in separate meetings and present to the larger team for discussion and review. Another important component of quality reviews and drafting team efforts is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Project Priority

Each project will be developed according to that project's priority status. While each standard project addresses particular industry needs, some projects will be identified as a higher priority project. A higher priority project may initially include a strict timeline, which may be needed to effectively respond to a FERC Directive or as determined by the NERC Board of Trustees. A higher priority project may also need to increase the frequency of meetings at any time throughout the development process to account for project timeline needs. Similarly, other priority projects may adjust to a lower frequency of meetings throughout the development process to reallocate resources to high priority projects.

This project has been identified as higher priority at this time. The project has a FERC deadline of November 4, 2025. To meet this deadline, the team will meet regularly, up to three times a week on conference calls, with face-to-face meetings scheduled as the members' schedule allows, up to twice a quarter.

Next Steps

The Standards Committee is expected to appoint members to the drafting team in August 2024. Nominees will be notified shortly after they have been appointed.

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

For more information or assistance, contact Senior Standards Developer, Laura Anderson (via email) or at 404-782-1870. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR” in the Title and Description Boxes.



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Atlanta, GA 30326
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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:	Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements		
Date Submitted:	4/29/24		
SAR Requester			
Name:	Alex Shattuck, Jamie Calderon, JP Skeath		
Organization:	North American Electric Reliability Corporation (NERC)		
Telephone:	470-259-0109 (Alex Shattuck) 404-960-0568 (Jamie Calderon) 404-823-1365 (JP Skeath)	Email:	Alex.Shattuck@nerc.net Jamie.Calderon@nerc.net John.Skeath@nerc.net

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

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

What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

This Standards Authorization Request (SAR) is initiated by NERC, with consultation of the Reliability Security Technical Committee, to address directives issued by FERC in Order No. 901. FERC issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. FERC Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBRs); including both utility scale and behind-the-meter or distributed energy resources (DERs).

Within the Order are four milestones that include sets of directives to NERC. In the Order, FERC has directed NERC to propose new or modified standards to mitigate reliability gaps in the current NERC Reliability Standards related to IBRs. Specifically, FERC directed NERC to develop new or modified

Requested information

Reliability Standards to address the following four broad topic areas related to IBRs: (1) data sharing; (2) data and model validation; (3) planning and operational studies; and (4) performance.

In January 2024, NERC filed the initial **Standards Development Work Plan in Response to FERC Order No. 901** (hereafter referred to as the "Work Plan"). A current version of the Work Plan will be maintained here. The Work Plan discusses how NERC will develop Reliability Standards within (Milestones 2-4) to meet FERC's filing deadlines. This Standard Authorization Request addresses Milestone 3 of the Work Plan, related to Reliability Standards for modeling and data sharing requirements to establish sufficient IBR model data and parameters to assure accurate representation of IBR performance within the models. Further, collaborative sharing of this information, and the utilization of this information throughout the lifecycle of IBRs will also be established.

Milestone 3 of the Work Plan covers the development of data provisioning, parameters, and estimation requirements for IBRs. FERC Order No. 901 directives address three categories of IBR: (1) registered IBR, including sub-Bulk Electric System IBRs to be registered under NERC's revised Compliance Registry criteria; (2) unregistered IBR; and (3) IBR-DER, to distinguish registered bulk connected IBRs from unregistered bulk connected IBRs as well as the transmission connected IBRs from distribution-connected IBRs. To be clear, assets to be included as part of revisions to the Compliance Registry criteria ("category 2 type assets") are considered herein as '"registered IBR". NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.

As often discussed within NERC recommendations and publications, the current paradigm of modeling and data sharing leaves the bulk power system (BPS) at a higher than necessary risk for unexpected and undesired inverter-based resource (IBR) performance. Since 2016, approximately 15,000 MW of IBR have unexpectedly reduced output during NERC categorized disturbance events. None of the IBR facilities involved in these disturbances utilized models that could accurately represent the facility's performance during the disturbance event. These discrepancies between modeled and studied performance when compared to real-world performance are driven by current industry modeling practices and a dependence on generic IBR modeling throughout the lifecycle of the IBR facility.

NERC Modeling Guidance [1] states that additional model types, namely manufacturer-specific user-written models, must be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance. The deficiencies within the current state of model quality are well documented. As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases.

Revisions to data sharing expectations and the creation of a "NERC Approved Model Library" that allows the use of manufacturer-specific models in addition to standard library (generic) models in instances

[1] https://www.nerc.com/pa/RAPA/ModelAssessment/Documents/Dynamic%20Modeling%20Recommendations.pdf

Requested information
where generic modeling cannot represent the performance of the IBR are necessary to ensure BPS reliability through improvements to the inputs of current study practices.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System (BES) being addressed, and how does this proposed project provide the reliability-related benefit described above?):
This SAR addresses specific pieces of the NERC filed Work Plan related to Milestone 3 and addresses the various industry comments to meet the regulatory directives of FERC Order No. 901. This project shall coordinate among other projects (i.e., act as a clearing house to tie directive language to standard revisions), develop standard language (i.e., perform the normal duties of a standard development Project), and build upon other Milestones from FERC Order No. 901 Standards Projects to meet regulatory deadlines (i.e., maintain agility based on how FERC Order No. 901 related Projects proceed to meet the directive deadlines). This Project will also address FERC Order No. 901 directives related to aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project is intended to serve as a data sharing center point for many of the revisions being established within all of the 901-related projects. Performance of IBR during an event (grid disturbance) are identified and corrected within the Standards Development projects pertaining to Milestone 2 of the Work Plan. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). Similarly, revisions to model validation being drafted by the drafting team assigned the Milestone 3 Part 2 SAR, must also assure entities follow the uniform model framework established here.
Project Scope (Define the parameters of the proposed project):
The FERC Order No. 901 directives assigned to this SAR are outlined in the Detailed Description section below. The project scope shall address all those directives, and should consider the following objectives during the standards development process: 1. Modify MOD-032 to require the usage of a “NERC-Approved Model Library” (Hereafter: “Model Library”) that contains acceptable (and unacceptable) models and recommendations to facilitate the exchange of neighboring entities’ respective planning and operation models and to be used in Interconnection-wide case creation and in other NERC Reliability Standards for IBR. a. This Model Library will be developed and maintained by NERC. Updates on the Model Library development will be coordinated with the Drafting Team. The Drafting Team may solicit feedback comments of the NERC process from industry as needed. b. The Model Library will be accessible to the general public. NERC will develop an open and transparent process for maintaining the library.

Requested information

c. The Model Library will be consistent with NERC's published Dynamic Modeling Recommendations, primarily:

i. Industry-approved library models are sufficient for use in Interconnection-wide base case creation and interconnection-wide studies;

ii. For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR.

2. Modify applicable Reliability Standards (e.g. MOD-032, TOP-003, and IRO-010) to require Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities to ensure usage of a uniform framework that includes modeling criteria consistent with NERC's Dynamic Modeling Recommendations, a registered modeling designee, and necessary data exchange requirements. The framework must require:

a. Data specification and notifications for the data necessary to develop interconnection-wide models and models for other reliability studies;

i. Specifications must include provisions for new, modified, or changed equipment,

ii. Specifications must include provisions for changes to an approved equipment-specific models,

iii. Specifications must include provisions and a periodicity for exchanging estimated aggregated unregistered IBR and DER data.

b. Data exchange of generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions;

c. A review and approval process for additional model types from the Model Library (other than generic model types) for other reliability studies;

d. Data exchange of aggregated data, estimation methods, and documented limitations of the availability of accurate data for unregistered IBR and DER as developed by Transmission Owners and Distribution Providers in Item 4.

3. Modify MOD-032 to require Generator Owners (GO) and Transmission Owners (TO) to follow the uniform framework developed in Item 2, specifically;

a. GO and TO of IBR must provide generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions;

b. GO and TO of IBR must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models.

i. For instance, a Corrective Action Plan created by a planner or operator to address model quality due to exceeded performance criteria (reference Milestone 3 Part 2 SAR), may

Requested information
necessitate usage of an equipment-specific model instead of a generic model from the Model Library. ii. For instance, studied discrepancies between the generic model and performance or the IBR demonstrated during the interconnection process may necessitate usage of an equipment-specific model instead of a generic model from the Model Library. iii. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e. from a post-event analysis) may necessitate usage of an equipment-specific model instead of a generic model from the Model Library. 4. Modify TOP-003 and IRO-010 to require Transmission Owners and Distribution Providers to establish and implement data aggregation methods for unregistered IBR and DER. These standards must address: a. An estimate of the modeling data and parameters of IBR-DERs and unregistered IBRs, b. An explanation of the limitations of the availability of accurate data, and c. The method used for all estimations. 5. The drafting team shall ensure that implementation plans for new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap during implementation.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The project scope above will need to account for the specific directive text in FERC Order 901 to be successful. The drafting team should consider the specific language in the FERC directives, as well as any comments in the underlying FERC Order No. 901 proceeding that FERC directed NERC to consider as part of the standard development process. **FERC Order 901 Directives Assigned to this SAR:** NERC will maintain a current version of NERC Standards Development's Work Plan to Address FERC Order No. 901 on the NERC website under Reliability Standards Under Development. Included in this Work Plan is a list of the directives in FERC Order No. 901 and their associated mapping of each SAR submitted by NERC. The Work Plan will be updated should any mapping of FERC directives be reassigned due to ongoing work in the various Standards Development Projects. As of April 1, 2024, this SAR will address the following FERC Order No. 901 directives, with the scope for this SAR emphasized in **bold** as appropriate:

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

Requested information

1. "Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate; and (2) data and model validation for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate." (P 7)
2. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information ,and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System." (P 76)
3. "Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." (P 77)
4. "As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P78)
5. "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." (P 86)
6. "Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System." (P 102)
7. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the

Requested information

availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." (P 104)

8. "To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters." (P 104)
9. "Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation." (P 105)
10. "In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters." (P 105)
11. "For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation." (P 106)
12. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear." (P 108)
13. "As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P 108)

Requested information

14. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models." (P 122)
15. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies." (P 124)
16. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models." (P 125)
17. "**We also direct NERC to require** the generator owners of registered IBRs and **the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of** registered and **unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior**." (P 141)
18. "Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives." (P 141)
19. "Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior)." (P141)
20. "Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in

Requested information
the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives." (P 141) 21. "Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models." (P 141) 22. "Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System." (P 141) 23. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to be able to perform respective system studies." (P 146) 24. "**Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate** and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models." (P 157) 25. "**Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models)** and the validation of each respective system model." (P 161) 26. "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." (P 226)
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):

Requested information
The associated cost with implementation of a new standard is currently unknown, and the modifications necessary for each specific directive are also unknown though they are expected to vary based on DT outcome.
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 connected to the transmission system.
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 NERC Rules of Procedure Appendix 5A:
This Project should contain appropriate members representing the following Functional Entities: Balancing Authority Distribution Provider Generator Owner Generator Operator Planning Coordinator Reliability Coordinator Transmission Owner Transmission Operator Transmission Planner Reliability Coordinator
Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
FERC Order No. 901 NERC Standards Development Work Plan in Response to FERC Order No. 901 Inverter-Based Resource Activities, Quick Reference Guide Distributed Energy Resource Activities, Quick Reference Guide IBR Registration Initiative, Quick Reference Guide
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)?
1. SARs: a. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation b. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision 2. Active Reliability Standards Projects: a. 2020-06 Verifications of Models and Data for Generators b. 2021-01 Modifications to MOD-025 and PRC-019

[3] 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
c. 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 (NERC Standards Development recommends assigning the SAR to this active project) d. 2022-04 EMT Modeling e. 2023-05 Modifications to FAC-001 and FAC-002 f. 2023-08 Modifications of MOD-031 Demand and Energy Data
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 with the benefits of using them.

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

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
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2022-02 Uniform Modeling Framework for IBR Standard Authorization Request (SAR)

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on the **Project 2022-02 Uniform Modeling Framework for IBR SAR** by **8 p.m. Eastern, Monday, June 24, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Laura Anderson (via email), or at 404-782-1870.

Background Information

FERC Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements SAR addresses regulatory directives from the NERC Standards Development Work Plan to respond to FERC Order No. 901. This project addresses the need to ensure the usage of a uniform framework for data sharing and model development. This project will also build mechanisms to allow equipment-specific models, if approved and as needed for model quality, to facilitate model changes as a result of the Milestone 2, 3, and 4 directives that evaluate performance of IBR.

This project must ensure modeling revisions from other IBR performance requirements in other 901-related projects will utilize the uniform framework. The drafting team will develop requirements for data aggregation estimation and data sharing of aggregated data for generation resources not registered by NERC Assets to be included as part of the revisions to the Compliance Registry criteria ("category 2 type assets") are considered "registered IBR" and not subject to the project objectives related to aggregated data or estimation methods.

This project has been identified as higher priority at this time. This project has a FERC deadline under Milestone 3 of November 4, 2025.

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:

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Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR Standard Authorization Request (SAR)

Formal Comment Period Open through June 24, 2024

Now Available

A formal comment period for the **Project 2022-02 Uniform Modeling Framework for IBR SAR**, is open through **8 p.m. Eastern, Monday, June 24, 2024**.

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

For more information or assistance, contact Senior Standards Developer, Laura Anderson (via email) or at 404-782-1870. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR” in the Title and Description Boxes.

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:	2022-02 Uniform Modeling Framework for IBR | Standard Authorization Request
Comment Period Start Date:	5/17/2024
Comment Period End Date:	6/24/2024
Associated Ballots:	

There were 34 sets of responses, including comments from approximately 113 different people from approximately 80 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

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

2. Provide any additional comments for the 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
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (SRC) Project 2022-02 IBR SAR	Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	SPP	2	MRO
Exelon	Daniel Gacek	1,3		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Entergy	Julie Hall	1,3,6		Entergy	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jamie Prater	Entergy	5	SERC
MRO	Michelle Olson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District	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	1,3,5,6	MRO

						(System Provider)		
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Corperation	1	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Terry Harbor	MidAmerican Energy Company	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power and Water	1,3,5,6	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas	1,3,5,6	MRO
DTE Energy - Detroit Edison Company	Mohamad Elhusseini	3,5		DTE Energy	Mohamad Elhusseini	DTE Energy	5	RF
					Patricia Ireland	DTE Energy	4	RF
					Marvin Johnson	DTE Energy - Detroit Edison Company	3	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC

					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	1,3,5,6		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	3	NPCC

	Edison Co. of New York		
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
					Ashley Stringer	Southwest Power Pool Inc.	2	MRO
					Jim Williams	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Mason Favazza	Southwest Power Pool Inc.	2	MRO
					Tim Miller	Southwest Power Pool Inc.	2	MRO
					Margaret Quispe	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Charles Cates	Southwest Power Pool Inc.	2	MRO
					Daniel Baker	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC

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.

Thomas Foltz - AEP - 3,5,6	
Answer	No
Document Name	

Comment

AEP does not agree with this proposed SAR and recommends that it not be pursued. Despite what modeling guidance may claim, standard library or generic models may not always be the best representation of IBRs or sufficient for use in interconnection-wide cases. Justification for use of equipment-specific or user-defined modeling should not be required. The decision between generic and user-defined models should be left to OEMs and Planning Coordinators / Transmission Planners per MOD-032 R1 data submittal documentation and not dictated in NERC standards. If equipment-specific models are supplied by OEMs and accepted by the PC and TP, it should not be necessary to also supply a generic model unless the PC and TP specify that in their model submittal documentation.

A fundamental problem that renewable generation has introduced at all levels (transmission, sub-transmission, and distribution) and one that these SARs are not truly acknowledging, is how to get verified and validated modeling in support of the interconnection study process such that the modeling studied prior to interconnection accurately represents the projects put into service. To do this verification and validation properly, which MOD-026-2 now under draft attempts to do only after projects are in service (and only BES interconnections), will require a similar process inserted into the interconnection timeline. Such an insertion is likely to extend project timelines and costs significantly. Not only that, we believe it is clear from the NERC disturbance reports that IBR ride-through performance is best evaluated by EMT modeling and simulation platforms given that the positive sequence phasor domain is limited in being able to represent all factors that can affect ride-through. The proposed SAR makes no mention of EMT.

A second problem that these SARs fail to acknowledge is that it is unknown how dynamic model estimation and aggregation of unregistered IBRs and DERs, which the SAR seeks to assign to TOs and DPs, is to be carried out. High-level assumptions must be made because, short of getting equipment-specific data and modeling these IBRs and DERs in individual detail (along with the subsystems to which they are connected, which detail is utterly impractical), there is no means to be certain what is out there and how it will behave in aggregate when put to the test. There have been previous attempts by SPIDER to impose DER modeling data requirements on TOs and DPs which were unsuccessful, at least in part because of the problematic nature of imposing compliance obligations on TOs and DPs to obtain data from unregistered entities. TPs and PCs, RCs and TOPs, TOs and DPs will all have to determine what assumptions to make (and those assumptions will have to be made to fulfill their existing obligations to system reliability as unregistered IBRs and DERs increase) however these functional entities should not be saddled with even more compliance obligations while trying to chart unknown methods of estimation and aggregation.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	

Comment

The Detailed Description section includes a listing of all FERC 901 directives assigned to Milestone 3. However, this SAR is only Part 1 of four SARS related to Milestone 3. On page 3 of this SAR it says the project scope shall address all those directives listed. To be clear, can the directives be rearranged and aligned with each of the expected four parts so that it is clear which ones apply. This will help the future drafting team.

In Scope item 1, it is noted to modify MOD-032 to require the usage of the NERC-Approved model library. The requirement is not clear whether there is grace period if NERC makes changes to the Model Library. Once NERC declares a model unacceptable, for example, it could take more than one year for an acceptable model to be developed to replace the unacceptable model and get added to the interconnection-wide models.

This SAR contains excessive language that creates confusion as to what the scope and goal of this SAR encompasses.

This SAR is attempting to perform several different functions. Project management and Standards development.

Is this a FERC Order 901 standard development coordination project, ie. Project Management, or a standards development project to address a specific risk? The coordination (project management) of the 901 projects should be separated from the specifics of Modeling and Data sharing requirements.

From the NERC Work Plan, Milestone 3 – Part 1, Data Sharing

Overall Strategy: Collaborate between NERC Standards Development, Engineering, and the RSTC. The scope of this collaboration is to cross check active projects, draft SARs, and pending SARs from RSTC-associated work plans and identify which of those will address aspects of this milestone. Some revisions to draft SARs or active projects will be necessary to focus development on directives in Order No. 901.

This is project management. Multiple projects, standards, and objectives. This can be accomplished outside of a SAR.

1. This project shall coordinate among other projects (i.e., act as a clearing house to tie directive language to standard revisions), develop standard language (i.e., perform the normal duties of a standard development Project), and build upon other Milestones from FERC Order No. 901 Standards Projects to meet regulatory deadlines (i.e., maintain agility based on how FERC Order No. 901 related Projects proceed to meet the directive deadlines).

2. This project is intended to serve as a data sharing center point for many of the revisions being established within all of the 901-related projects. Performance of IBR during an event (grid disturbance) are identified and corrected within the Standards Development projects pertaining to Milestone 2 of the Work Plan. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). Similarly, revisions to model validation being drafted by the drafting team assigned the Milestone 3 Part 2 SAR, must also assure entities follow the uniform model framework established here.

3. NERC Modeling Guidance states that additional model types, namely manufacturer-specific user-written models, must be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance. The deficiencies within the current state of model quality are well documented. As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases.

4. The creation of a “NERC Approved Model Library” that allows the use of manufacturer-specific models in addition to standard library (generic) models in instances.

Additionally, MH requests coordination of this SAR and Project across all IBR/Order 901 Projects to ensure that all the projects collectively address the directives in FERC Order 901 without introducing duplication, overlap or contradictions between projects.

MH is concerned that the SAR does not appear to align with what’s in NERC’s Dynamic Modeling Recommendations whitepaper (see Figure 1).[1]

[1] Dynamic Modeling Recommendations (nerc.com)

Example #1

While the SAR (bottom of page 2) states that: "*NERC Modeling Guidance 1 states that additional model types, namely manufacturer-specific user-written models, must be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance.*"

NERC's Dynamic Modeling Recommendations whitepaper, Figure 1 illustrates that both "**Recommended User Defined Models**" and "**Benchmarked (against UDM or EMT) Library Models Recommended**" can be used for "**Local Reliability Studies**" and "**Plant Interconnection Studies.**"

The SAR also appears to contain conflicts within itself as with the first bullet above (SAR, bottom of page 2) and this bullet (SAR, page 4, section 1.c.ii.):

"For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR."

Example #2

Likewise, there appears to be another conflict between NERC's Dynamic Modeling Recommendations whitepaper and the SAR (page 2): "*As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases." Here again, the whitepaper illustrates that "Recommended User-Defined Models" are also acceptable.*"

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	No
Document Name	

Comment

While beneficial in having all models in one location for use, the creation and maintenance of said Model Library will be significant. Should the RSTC be the owner of the library versus NERC? The FERC Order just directed "NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models" which does not necessarily imply that NERC develops and maintains a Model Library. The SAR indicates that the development of the Model Library will be coordinated with the Drafting Team. Also, the Drafting Team may solicit feedback from industry on the NERC process. This assumes that the Model Library will be developed as the Standard is developed. It does not consider timing period beyond the life of the DT. Also, the comments from industry will be managed through what mechanism? What recourse is considered if the model does not exist in the Model Library? It appears the DT is creating a solution within the SAR and Standard Development efforts that are best left with NERC working with the RSTC when a Model Library is required by approved Standard language.

How will model changes be tracked (and by whom)?

How does this affect FAC-001 and FAC-002 in terms of using the Model Library as a consistent source for modeling?

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Reference 2022-02 Uniform Modeling Framework for IBR Standard Authorization Request, Project Scope section, Version 5, August 14, 2023, for the following Duke Energy recommendations (Questions 1 and 2):

2.a.iii: Minimum threshold for unregistered and aggregate DER should be considered individually to ensure consistently.

2.c: Duke Energy does not believe the PC, TP, RC, TO, TOP, BA have the expertise to approve additional model types. This review and approval process should be handled by an industry group.

4.c: Estimation Methodology should include minimum threshold for modeling (e.g., Aggregate MWs or IBR-DER Penetration Percentage).

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy

Answer	No
Document Name	

Comment

What criteria is to be used and by whom to determine if generic models cannot accurately represent the IBR?

Item #3 under project scope notes that the GO and TO of IBRs must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for use of equipment specific models. What criteria is to be used to make the determination that an equipment specific model should be used?

There is a disconnect between MOD-032 models and what is used as part of the interconnection process. There should be no difference on what models are used for both and MOD-032 should address the interconnection process models as well to eliminate confusion between the two processes.

The SAR Detailed Description section does not provide detail on proposed deliverables to address the directives in FERC Order 901, but rather just restates the directives, which does not meet the intent of this section of the SAR.

The SAR does not provide a clear direction for the industry to evaluate since it still notes several possible paths that need to be determined. Without knowing the path the SDT is taking, we cannot effectively evaluate the SAR.

Allowing a TO or DP to estimate the unregistered IBRs or IBR-DERs that are on their systems does not align with the FERC Order 901 directive to accurately represent the dynamic performance of these facilities.

DP's are not able to estimate unregistered IBR-DER to provide models that meet the level of accuracy required for the purpose of studying the impact of IBR's on the grid. There are also state regulations that may not allow DP's to ask for this type of modeling data. DP's also cannot estimate which

unregistered IBR_DER's can impact the grid. It is recommended for Nerc to work with the RTO's and with the state regulators to mandate this type of data to be supplied and to the extent possible, verified.

Requiring modeling for unregistered IBRs and IBR-DERs is going to be a large cost impact to the affected entities especially if equipment specific models are to be used. For a recent wind project, the initial modelling costs for the site was nearly $500k for a 225MW site with two turbine OEMs and a plant level controller. Equipment specific models were used in this instance and will require on-going O&M costs with the respective OEMs to update the equipment specific models for new model versions and any changes to the site.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AZPS supports the following comments that were submitted by EEI on behalf of its members:

Project Scope Comments: FERC directives identified in the Detail Description Section as Items 1, 2, 4, 6, 9, 12, 14, 16, 18, 19, 20, 22, 23 and 26 are sufficiently covered in this SAR, assuming adjustments are made in line with the proposed edits below. We further note that Items 3, 5, 8, and 10 do not appear as tasks within the proposed scope, however, all four were identified as directives and need to be addressed. (Noting the following)

Item 3: Consider AEU's and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria and necessary data exchange.

Item 5: Consider CAISO's suggestion to require registered entities to provide additional IBR data points (e.g., telemetry collections or other automated platform integrations) to further enhance real-time visibility of Bulk-Power System operations.

Item 8: Consider new processes or mechanisms to provide Transmission Owners with modeling data and parameters.

Item 10: Consider new processes or mechanisms to provide Distribution Providers with modeling data and parameters.

And lastly, we read Items 11, 17, 21 and 24 to be NERC directed tasks and believe those activities should be removed from the Detailed Description section of this SAR and addressed separately by NERC. Beyond this we offer the following edits to the 5 Items identified in the SAR Project Scope.

Scope Item 1 Comments: Item 1 only contains one task that directly aligns to the work the DT will perform under this project. The rest of Item 1 describes the model library and its attributes and processes, all of which are NERC activities. While we have no concerns with NERC taking responsibility for the model library, it is critical that models contained in that library are compatible with all existing planning software currently available and changes to the model library are only allowed during prescribed intervals/time periods so as not to disrupt responsible entity planning compliance obligations and deadline causing unnecessary rework of planning studies. Given the model library will be done exclusively by NERC and not the DT, Item 1 should be revised to read as follows:

1. Modify MOD-032 to require the usage of a "NERC-Approved Model Library"

Item 2 Comments: EEI suggests removing the reference to NERC's Dynamic Modeling Requirements. While we do not object to using that document as a guide, such language potentially limits the DT from developing requirements that they believe better align with the directive contained in Order 901.

EEI also does not agree with mixing the modeling data requirements associated with MOD-032 with the data collection requirements of TOP-003 and IRO-010. The SAR will be clearer separating these DT tasks. To address these concerns, we offer the following edits to Item 2 below:

2a) Modify Reliability Standard MOD-032 or develop a new Reliability Standard that require**s** Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities to use a uniform framework with modeling criteria for each interconnection. The DT should consider integrating appropriate element of NERC's Dynamic Modeling Recommendations as a guide. The revised or new Reliability Standard should contain:

d. Data specification for the data necessary to develop interconnection-wide models and models for other reliability studies;

i. Specifications must include provisions for new, modified, or changed equipment,

ii. Specifications must include provisions for changes to an approved equipment- specific models,

iii. Specifications must include provisions and a periodicity for exchanging estimated aggregated unregistered IBR and DER data.

e. Data exchange of generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short- circuit, and dynamic conditions;

f. Delete

g. Data exchange of aggregated data, estimation methods, and documented limitations of the availability of accurate data for unregistered IBR and DER as developed by Transmission Owners and Distribution Providers in Item 4.

2b: Modify TOP-003 and IRO-010 or develop new Reliability Standards for the collection of IBR specific models and data that align with the defined specifications as developed within the modified MOD-032 Reliability Standard or new Reliability Standard.

Item 3 Comments: EEI does not agree that MOD-032 is the proper Reliability Standard to require GOs to provide IBR models and data. And while TOs and DPs will be responsible for providing IBR models and data for unregistered IBRs and IBR-DERs in aggregate, TOs should have no part in providing IBR models or data for registered IBRs. To address our concern, we offer the following edits to Item 3:

3. Modify TOP-003 and IRO-010 to require Generator Owners (GO) to provide IBR models and data that conform to the specifications contained in MOD-032, or the new IBR Reliability Standard that meets the requirements identified in Item 2 above, specifically;

a. GO of registered IBR must provide generic models from the Model Library for interconnection- wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions;

b. GO of registered IBR must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models.

i. For instance, a Corrective Action Plan created by a planner or operator to address model quality due to exceeded performance criteria (reference Milestone 3 Part 2 SAR), may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

ii. For instance, studied discrepancies between generic model and performance or IBR demonstrated during the interconnection process may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

iii. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e. from a post-event analysis) may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

c. TOs who have unregistered IBRs and DPs who have IBR-DERs that have a material impact on the BPS must provide aggregated dynamic models that adequately represent the dynamic performance of those resources;

d. TOs who have unregistered IBR and DPs who have IBR-DERs that have a material impact on the BPS must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models if unable to gather data from the

affected aggregated resources that have a material impact on the Bulk-Power System, providing to the responsible planners and operators a dynamic model using estimated data for those resources.

Item 4 Comments: EEI does not agree that TOP-003 and IRO-010 are appropriate Reliability Standards to develop aggregation processes for TOs and DPs that have been notified by Transmission Planners that they have unregistered IBRs that materially impact, in aggregate, the reliability of the BPS. To address the Order 901 directives associated with identifying aggregated unregistered IBRs and IBR-DERs that have a material impacts on the BPS, the establishment and implementation of aggregation methods for unregistered IBRs and IBR-DERs that have been defined as having material impacts, and processes for developing and providing estimated data and identifying models for aggregated unregistered IBRs and IBR-DERs that adequately represent the dynamic performance of those resources we suggest the development of a new Reliability Standard. To address these concerns, we offer the following edits for consideration.

4. Develop a new Reliability Standard that:

a. Requires Transmission Planners to identify and notify responsible TOs and DPs when they have unregistered IBRs and IBR-DERs that are having a material impact on BPS reliability.

b. Requires Transmission Owners and Distribution Providers to establish and implement data aggregation methods for unregistered IBRs and IBR-DERs, when they have been notified by their Transmission Planner that these resources are having a material impact on BPS reliability. These processes must address:

- An estimate of the modeling data and parameters of IBR-DERs and unregistered IBRs in aggregate that account for the material impacts on the BPS,
- Selection of dynamic models that they determine to adequately represent the dynamic performance of the unregistered IBRs and IBR-DERs that are materially impacting the BPS,
- An explanation of the limitations of the availability of accurate data, and
- The method used for all estimations.

Item 5 Comments: EEI does not agree that this drafting team should be overseeing work done by other drafting teams. It is sufficient for this drafting team to coordinate with other drafting teams to ensure their work does not duplicate or otherwise overlap the work of other drafting teams. To address our concerns. We offer the following edits:

The drafting team shall coordinate with other drafting teams that have overlapping work, particularly those working on Order 901 directives in order to ensure that new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap.

Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	

As explicitly stated, the intent of the uniform framework for data sharing and model development is to ensure all directive of FERC order 901 can be effectively met and all impacted parties/users of the approved models are informed and provided approved models as a result of any requisite changes due to correcting IBR performance. While Constellation agrees with the intent, we are not sure a new standard added is going to be effective in informing and guiding the industry. This will only be burdensome and likely drive confusions as too many processes are being created/revised in short amount of time.

Kimberly Turco on behalf of Segements 5 and 6

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

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1,3, Group Name Eversource

Answer	No
Document Name	

Comment

There needs to be part of the scope which specifies that the mechanism for royalty-free sharing of all required and allowed models will be documented.

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 agree with the proposed scope as described in the draft SAR for the following reasons:

a. The NAGF recommends that the SAR identify actions to be performed by the Drafting Team. Including unapplicable/background narrative from FERC Order 901 directives in the SAR only adds confusion and uncertainty as to the actions to be performed by the DT.

b. SAR Comment Form Background Information section (page 1) – The NAGF requests additional clarification regarding the statement “Assets to be included as part of the revisions to the Compliance Registry criteria (category 2 type assets) are considered “registered IBR” and not subject to the project objectives related to aggregated data or estimation methods”. The NAGF is unclear as to the reason that developed aggregated data or estimation methods would not apply to determining new category GO/GOPs (Category 2) IBRs that “contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA”.

c. Project Scope comments:

i. Item 1– The NAGF recommends that the NERC-Approved Model Library contain only the acceptable models. Including unacceptable models does not provide value.

ii. Item 1a/b/c – The NAGF understands that NERC will be responsible for developing and maintaining the Model Library. However, it is unclear what work activities, if any, the Drafting Team will perform regarding the Model Library. Coordinating Model Library development with the DT is an administrative function that does not require specific DT work activities. Therefore, recommend removing Items 1a/b/c from the SAR Project Scope section.

iii. Item 3. – The NAGF recommends using a process similar to that currently used for synchronous generation.

d. Detailed Description Section:

i. FERC Order 901 Directives Assigned to this SAR (page 5) – The paragraph states “As of April 1, 2024, this SAR will address the following FERC Order 901 directives, with the scope for this SAR emphasized in bold as appropriate:”. 26 sections of the FERC Order 901 directives are included in the Detailed Description Section of which only 3 are bolded (17, 24, and 25). It is unclear as to value of including the non-bolded narratives and it adds significant confusion to the SAR. Recommend removing the non-bolded FERC Order 901 directive narratives from this section or clearly identify DT work activities associated with these non-bolded narratives.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

Project Scope Comments: FERC directives identified in the Detail Description Section as Items 1, 2, 4, 6, 9, 12, 14, 16, 18, 19, 20, 22, 23 and 26 are sufficiently covered in this SAR, assuming adjustments are made in line with the proposed edits below. We further note that Items 3, 5, 8, and 10 do not appear as tasks within the proposed scope, however, all four were identified as directives and need to be addressed. (Noting the following)

a. Item 3: Consider AEU's and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria, and necessary data exchange.

b. }Item 5: Consider CAISO's suggestion to require registered entities to provide additional IBR data points (e.g., telemetry collections or other automated platform integrations) to further enhance real-time visibility of Bulk-Power System operations.

c. Item 8: Consider new processes or mechanisms to provide Transmission Owners with modeling data and parameters.

d. Item 10: Consider new processes or mechanisms to provide Distribution Providers with modeling data and parameters.

And lastly, we read Items 11, 17, 21 and 24 to be NERC directed tasks and believe those activities should be removed from the Detailed Description section of this SAR and addressed separately by NERC. Beyond this we offer the following edits to the 5 Items identified in the SAR Project Scope. All of our edits are in boldface below:

Scope Item 1 Comments: Item 1 only contains one task that directly aligns to the work the DT will perform under this project. The rest of Item 1 describes the model library and its attributes and processes, all of which are NERC activities. While we have no concerns with NERC taking responsibility for the model library, it is critical that models contained in that library are compatible with all existing planning software currently available and changes to the model library are only allowed during prescribed intervals/time periods so as not to disrupt responsible entity planning compliance obligations and deadline causing unnecessary rework of planning studies. Given the model library will be done exclusively by NERC and not the DT, Item 1 should be revised as follows:

Modify MOD-032 to require the usage of a "NERC-Approved Model Library" **Item 2 Comments:** EEI suggests removing the reference to NERC's Dynamic Modeling Requirements. While we do not object to using that document as a guide, such language potentially limits the DT from developing requirements that they believe better align with the directive contained in Order 901. EEI also does not agree with mixing the modeling data requirements associated with MOD-032 with the data collection requirements of TOP-003 and IRO-010. The SAR will be clearer separating these DT tasks. To address these concerns, we offer the following edits to Item 2 below:

2a) Modify Reliability Standard MOD-032 **or develop a new Reliability Standard that** require**s** Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities to **use** a uniform framework **with modeling criteria for each interconnection. The DT should consider integrating appropriate elements of** NERC's Dynamic Modeling Recommendations**, using this document as a guide.** The **revised or new Reliability Standard should contain**:

a) Data specification for the data necessary to develop interconnection-wide models and models for other reliability studies;

}i) Specifications must include provisions for new, modified, or changed equipment,

ii) Specifications must include provisions for changes to an approved equipment-specific models,

iii) Specifications must include provisions and a periodicity for exchanging estimated aggregated unregistered IBR and DER data.

b) Data exchange of generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short- circuit, and dynamic conditions;

c) Data exchange of aggregated data, estimation methods, and documented limitations of the availability of accurate data for unregistered IBR and DER as developed by Transmission Owners and Distribution Providers in Item 4.

2b: **Modify TOP-003 and IRO-010 or develop new Reliability Standards for the collection of IBR specific models and data that align with the defined specifications as developed within the modified MOD-032 Reliability Standard or new Reliability Standard.**

Item 3 Comments: EEI does not agree that MOD-032 is the proper Reliability Standard to require GOs to provide IBR models and data. And while TOs and DPs will be responsible for providing IBR models and data for unregistered IBRs and IBR-DERs in aggregate, TOs should have no part in providing IBR models or data for registered IBRs. To address our concern, we offer the following edits to Item 3:

3. Modify **TOP-003 and IRO-010** to require Generator Owners (GO) to **provide IBR models and data that conform to the specification for contained in MOD-032, or the new IBR Reliability Standard that meets the requirements identified in** Item 2 **above**, specifically;

a. GO of **registered** IBR must provide generic models from the Model Library for interconnection- wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions;

b. GO of **registered** IBR must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models.

i. For instance, a Corrective Action Plan created by a planner or operator to address model quality due to exceeded performance criteria (reference Milestone 3 Part 2 SAR), may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

ii. For instance, studied discrepancies between generic model and performance or IBR demonstrated during the interconnection process may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

iii. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e., from a post-event analysis) may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

c. **TOs who have unregistered IBRs and DPs who have IBR-DERs that have a material impact on the BPS must provide aggregated dynamic models that adequately represent the dynamic performance of those resources;**

d. **TOs who have unregistered IBR and DPs who have IBR-DERs that have a material impact on the BPS must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models if unable to gather data from the affected aggregated resources that have a material impact on the Bulk-Power System, providing to the responsible planners and operators a dynamic model using estimated data for those resources.**

Item 4 Comments: EEI does not agree that TOP-003 and IRO-010 are appropriate Reliability Standards to develop aggregation processes for TOs and DPs that have been notified by Transmission Planners that they have unregistered IBRs that materially impact, in aggregate, the reliability of the BPS. To address the Order 901 directives associated with identifying aggregated unregistered IBRs and IBR-DERs that have a material impacts on the BPS, the establishment and implementation of aggregation methods for unregistered IBRs and IBR-DERs that have been defined as having material impacts, and processes for developing and providing estimated data and identifying models for aggregated unregistered IBRs and IBR-DERs that adequately represent the dynamic performance of those resources we suggest the development of a new Reliability Standard. To address these concerns, we offer the following edits for consideration.

4. **Develop a new Reliability Standard that:**

a. **Requires Transmission Planners to identify and notify responsible TOs and DPs when they have unregistered IBRs and IBR-DERs that are having a material impact on BPS reliability.**

b. **R**equire**s** Transmission Owners and Distribution Providers to establish and implement data aggregation methods for unregistered IBR**s** and **IBR-**DER**s**, **when they have been notified by their Transmission Planner that these resources are having a material impact on BPS reliability**. These **processes** must address:

• An estimate of the modeling data and parameters of IBR-DERs and unregistered IBRs **in aggregate that account for the material impacts on the BPS**,

• **Selection of dynamic models that they determine to adequately represent the dynamic performance of the unregistered IBRs and IBR-DERs that are materially impacting the BPS,**

• An explanation of the limitations of the availability of accurate data, and

• The method used for all estimations.

Item 5 Comments: EEI does not agree that this drafting team should be overseeing work done by other drafting teams. It is sufficient for this drafting team to coordinate with other drafting teams to ensure their work does not duplicate or otherwise overlap the work of other drafting teams. To address our concerns. We offer the following edits:

The drafting team shall **coordinate with other drafting teams that have overlapping work, particularly those working on Order 901 directives in order to ensure that** new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI's comprehensive comments, included here:

Project Scope Comments: FERC directives identified in the Detail Description Section as Items 1, 2, 4, 6, 9, 12, 14, 16, 18, 19, 20, 22, 23 and 26 are sufficiently covered in this SAR, assuming adjustments are made in line with the proposed edits below. We further note that Items 3, 5, 8, and 10 do not appear as tasks within the proposed scope, however, all four were identified as directives and need to be addressed. (Noting the following)

a. Item 3: Consider AEU's and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria and necessary data exchange.

b. Item 5: Consider CAISO's suggestion to require registered entities to provide additional IBR data points (e.g., telemetry collections or other automated platform integrations) to further enhance real-time visibility of Bulk-Power System operations.

c. Item 8: Consider new processes or mechanisms to provide Transmission Owners with modeling data and parameters.

d. Item 10: Consider new processes or mechanisms to provide Distribution Providers with modeling data and parameters.

And lastly, we read Items 11, 17, 21 and 24 to be NERC directed tasks and believe those activities should be removed from the Detailed Description section of this SAR and addressed separately by NERC. Beyond this we offer the following edits to the 5 Items identified in the SAR Project Scope. All of our edits are in boldface below:

Scope Item 1 Comments: Item 1 only contains one task that directly aligns to the work the DT will perform under this project. The rest of Item 1 describes the model library and its attributes and processes, all of which are NERC activities. While we have no concerns with NERC taking responsibility for the model library, it is critical that models contained in that library are compatible with all existing planning software currently available and changes to the model library are only allowed during prescribed intervals/time periods so as not to disrupt responsible entity planning compliance obligations and deadline causing unnecessary rework of planning studies. Given the model library will be done exclusively by NERC and not the DT, Item 1 should be revised as follows:

1) Modify MOD-032 to require the usage of a "NERC-Approved Model Library" (*remove:* ***(Hereafter: "Model Library") that contains acceptable (and unacceptable) models and recommendations to facilitate the exchange of neighboring entities' respective planning and operation models and to be used in Interconnection-wide case creation and in other NERC Reliability Standards for IBR.***

a) This Model Library will be developed and maintained by NERC. Updates on the Model Library development will be coordinated with the Drafting Team. The Drafting Team may solicit feedback comments of the NERC process from industry as needed.

b) The Model Library will be accessible to the general public. NERC will develop an open and transparent process for maintaining the library.

c) The Model Library will be consistent with NERC's published Dynamic Modeling Recommendations, primarily:

i) Industry-approved library models are sufficient for use in Interconnection-wide base case creation and interconnection-wide studies;

For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR.)

Item 2 Comments: EEI suggests removing the reference to NERC's Dynamic Modeling Requirements. While we do not object to using that document as a guide, such language potentially limits the DT from developing requirements that they believe better align with the directive contained in Order 901. EEI also does not agree with mixing the modeling data requirements associated with MOD-032 with the data collection requirements of TOP-003 and IRO-010. The SAR will be clearer separating these DT tasks. To address these concerns, we offer the following edits to Item 2 below:

2a) Modify (*remove:* ***applicable***) Reliability Standard (*remove:* ***s (e.g.***) MOD-032 (*remove:* ***, TOP-003, and IRO-010)***) **or develop a new Reliability Standard that to** require**s** Planning Coordinators, Transmission Planners, Reliability Coordinators, Transmission Operators, and Balancing Authorities to (*remove:* ***ensure usage of***) **use** a uniform framework **with modeling criteria for each interconnection.** (*remove:* ***that includes modeling criteria consistent with***) **The DT should consider integrating appropriate element of** NERC's Dynamic Modeling Recommendations (*remove:* ***, a***) **as a guide.** (*remove:* ***registered modeling designee, and necessary data exchange requirements.***) The (*remove:* ***framework must require***) **revised or new Reliability Standard should contain**:

d) Data specification (*remove:* ***and notifications***) for the data necessary to develop interconnection-wide models and models for other reliability studies;

i) Specifications must include provisions for new, modified, or changed equipment,

ii) Specifications must include provisions for changes to an approved equipment-specific models,

iii) Specifications must include provisions and a periodicity for exchanging estimated aggregated unregistered IBR and DER data.

e) Data exchange of generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short- circuit, and dynamic conditions;

(remove: **f)** ***A review and approval process for additional model types from the Model Library (other than generic model types) for other reliability studies;)***)

g) Data exchange of aggregated data, estimation methods, and documented limitations of the availability of accurate data for unregistered IBR and DER as developed by Transmission Owners and Distribution Providers in Item 4.

2b: **Modify TOP-003 and IRO-010 or develop new Reliability Standards for the collection of IBR specific models and data that align with the defined specifications as developed within the modified MOD-032 Reliability Standard or new Reliability Standard.**

Item 3 Comments: EEI does not agree that MOD-032 is the proper Reliability Standard to require GOs to provide IBR models and data. And while TOs and DPs will be responsible for providing IBR models and data for unregistered IBRs and IBR-DERs in aggregate, TOs should have no part in providing IBR models or data for registered IBRs. To address our concern, we offer the following edits to Item 3:

3. Modify (*remove:* ***MOD-032***) **TOP-003 and IRO-010** to require Generator Owners (GO) to **provide** (*remove:* ***follow the uniform framework developed in)*** **IBR models and data that conform to the specification for contained in MOD-032, or the new IBR Reliability Standard that meets the requirements identified in** Item 2 **above**, specifically;

a. GO (*remove:* ***and TO***) of **registered** IBR must provide generic models from the Model Library for interconnection- wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions;

b. GO (*remove:* ***and TO***) of **registered** IBR must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models.

i. For instance, a Corrective Action Plan created by a planner or operator to address model quality due to exceeded performance criteria (reference Milestone 3 Part 2 SAR), may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

ii. For instance, studied discrepancies between generic model and performance or IBR demonstrated during the interconnection process may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

iii. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e. from a post-event analysis) may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

c. **TOs who have unregistered IBRs and DPs who have IBR-DERs that have a material impact on the BPS must provide aggregated dynamic models that adequately represent the dynamic performance of those resources;**

d. **TOs who have unregistered IBR and DPs who have IBR-DERs that have a material impact on the BPS must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models if unable to gather data from the affected aggregated resources that have a material impact on the Bulk-Power System, providing to the responsible planners and operators a dynamic model using estimated data for those resources.**

Item 4 Comments: EEI does not agree that TOP-003 and IRO-010 are appropriate Reliability Standards to develop aggregation processes for TOs and DPs that have been notified by Transmission Planners that they have unregistered IBRs that materially impact, in aggregate, the reliability of the BPS. To address the Order 901 directives associated with identifying aggregated unregistered IBRs and IBR-DERs that have a material impacts on the BPS, the establishment and implementation of aggregation methods for unregistered IBRs and IBR-DERs that have been defined as having material impacts, and processes for developing and providing estimated data and identifying models for aggregated unregistered IBRs and IBR-DERs that adequately represent the dynamic performance of those resources we suggest the development of a new Reliability Standard. To address these concerns, we offer the following edits for consideration.

4. *(remove:* ***Modify TOP-003 and IRO-010 to***) **Develop a new Reliability Standard that:**

a. **Requires Transmission Planners to identify and notify responsible TOs and DPs when they have unregistered IBRs and IBR-DERs that are having a material impact on BPS reliability.**

b. **R**equire**s** Transmission Owners and Distribution Providers to establish and implement data aggregation methods for unregistered IBR**s** and **IBR-**DER**s**, **when they have been notified by their Transmission Planner that these resources are having a material impact on BPS reliability**. These (*remove: **standards***) **processes** must address:

• An estimate of the modeling data and parameters of IBR-DERs and unregistered IBRs **in aggregate that account for the material impacts on the BPS**,

• **Selection of dynamic models that they determine to adequately represent the dynamic performance of the unregistered IBRs and IBR-DERs that are materially impacting the BPS,**

• An explanation of the limitations of the availability of accurate data, and

• The method used for all estimations.

Item 5 Comments: EEI does not agree that this drafting team should be overseeing work done by other drafting teams. It is sufficient for this drafting team to coordinate with other drafting teams to ensure their work does not duplicate or otherwise overlap the work of other drafting teams. To address our concerns. We offer the following edits:

The drafting team shall **coordinate with other drafting teams that have overlapping work, particularly those working on Order 901 directives in order to ensure that** (*remove: **ensure that implementation plans for***) new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap (*remove: **during implementation***.)

Likes 0	
Dislikes 0	

Response

Michelle Olson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

This SAR contains excessive language that creates confusion as to what the scope and goal of this SAR encompasses.

This SAR is attempting to perform several different functions. Project management and Standards development.

Is this a FERC Order 901 standard development coordination project, ie. Project Management, or a standards development project to address a specific risk? The coordination (project management) of the 901 projects should be separated from the specifics of Modeling and Data sharing requirements.

From the NERC Work Plan, Milestone 3 – Part 1, Data Sharing

Overall Strategy: Collaborate between NERC Standards Development, Engineering, and the RSTC. The scope of this collaboration is to cross check active projects, draft SARs, and pending SARs from RSTC-associated work plans and identify which of those will address aspects of this milestone. Some revisions to draft SARs or active projects will be necessary to focus development on directives in Order No. 901.

This is project management. Multiple projects, standards, and objectives. This can be accomplished outside of a SAR.

1. This project shall coordinate among other projects (i.e., act as a clearing house to tie directive language to standard revisions), develop standard language (i.e., perform the normal duties of a standard development Project), and build upon other Milestones from FERC Order No. 901 Standards Projects to meet regulatory deadlines (i.e., maintain agility based on how FERC Order No. 901 related Projects proceed to meet the directive deadlines).

2. This project is intended to serve as a data sharing center point for many of the revisions being established within all of the 901-related projects. Performance of IBR during an event (grid disturbance) are identified and corrected within the Standards Development projects pertaining to Milestone 2 of the Work Plan. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). Similarly, revisions to model validation being drafted by the drafting team assigned the Milestone 3 Part 2 SAR, must also assure entities follow the uniform model framework established here.

3. {C}NERC Modeling Guidance states that additional model types, namely manufacturer-specific user-written models, must be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance. The deficiencies within the current state of model quality are well documented. As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases.

4. The creation of a “NERC Approved Model Library” that allows the use of manufacturer-specific models in addition to standard library (generic) models in instances.

Additionally, MRO NSRF requests coordination of this SAR and Project across all IBR/Order 901 Projects to ensure that all the projects collectively address the directives in FERC Order 901 without introducing duplication, overlap or contradictions between projects.

MRO NSRF is concerned that the SAR does not appear to align with what’s in NERC’s Dynamic Modeling Recommendations whitepaper (see Figure 1).[1]

Example #1

{C}· While the SAR (bottom of page 2) states that: “*NERC Modeling Guidance 1 states that additional model types, namely manufacturer-specific user-written models, must be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance.”*

{C}· {C}NERC's Dynamic Modeling Recommendations whitepaper, Figure 1 illustrates that both "**Recommended User Defined Models**" and "**Benchmarked (against UDM or EMT) Library Models Recommended**" can be used for "**Local Reliability Studies**" and "**Plant Interconnection Studies.**"

{C}· The SAR also appears to contain conflicts within itself as with the first bullet above (SAR, bottom of page 2) and this bullet (SAR, page 4, section 1.c.ii.):

"For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR."

Example #2

Likewise, there appears to be another conflict between NERC's Dynamic Modeling Recommendations whitepaper and the SAR (page 2): "*As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases." Here again, the whitepaper illustrates that "Recommended User-Defined Models" are also acceptable.*"

[1] Dynamic Modeling Recommendations (nerc.com)

Likes 0	
Dislikes 0	

Response

Christy Thompson - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC

Answer	No
Document Name	

Comment

Louisville Gas and Electric Co. agrees generally with the EEI comments but would like to provide additional specific comments.

The section addressing potential BES risk incorrectly states that "NERC Modeling Guidance states that additional model types, namely manufacturer-specific user-written models, **must** be used for local reliability studies, during the interconnection process and following commissioning …" This is an overstatement at best, as the referenced Modeling Guidance is 1) guidance, and 2) clearly says the suggested practice is "strongly recommended". Further, the same document plainly says that with multiple models available, "GOs, TPs, and PCs should have enough information to use engineering judgement to determine which model is most appropriate for each study."

Regarding item (1), FERC Order 901 states:

"Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models. One example of a way NERC could meet this directive would be to require an equivalent generic library model along with all submissions of user defined models so that the generic library model can be used when combining neighboring transmission system models and in interconnection-wide models."

The suggestion in item 1 of the SAR to utilize a “NERC-Approved Model Library” goes beyond the directive. The current practice of maintaining a list of unapproved models or models that have identified issues could be sufficient if paired with a requirement such as, “dynamic models utilized in interconnection-wide models must be compatible with the simulation software employed in the processes used to build such models.” Establishing a “NERC-Approved Model Library” (as opposed to the list of unapproved/problematic models) will only serve to slow industry adoption of updated or improved models. Once major software vendors have introduced such models into their standard model libraries, entities should be able to utilize those models without this additional hurdle.

Additionally, entities are likely to move very slowly in supporting the approval of new models into a “NERC-Approved Model Library” since new models typically require software updates, code/script changes, etc. Thus, this additional step will slow the adoption of improved generic models and decrease the incentive for entities to maintain automation and processes that is compatible with the latest version of industry standard analysis software.

Regarding item (1)(c)(ii), the SAR should be modified to align with the actual language of the Dynamic Modeling Recommendations, which is that 1) user-written models are recommended for this type of study, and 2) the TP/PC/GO should use engineering judgment to determine which model is appropriate.

Regarding item (2), the only modification necessary is the addition of explicit requirements that entities submitting data for interconnection-wide models utilize models that are compatible with the simulation software utilized to build such models. For example, if Siemens PTI PSS®E were to introduce a new IBR model type that was not supported by GE PSLF, entities should not utilize it for interconnection-wide cases as it would preclude GE PSLF users from using the models. However, if the model has been adopted by the major software vendors, no additional approval should be necessary (beyond the model verification that will already take place via MOD-026/027, etc.)

Regarding item (3)(a), the SAR should remove the requirement to “provide generic models from the Model Library” and instead reference only “generic models”. This comment is consistent with the comments above. The SAR must be modified to allow for an option other than the creation and maintenance of a “NERC-Approved Model Library”.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC (CEHE) does not support this project’s scope, particularly objective three of the SAR. CEHE supports the comments as submitted by the Edison Electric Institute (EEI), in particular, the issue around the statements requiring the TOs to provide the generic models, specifications, parameter information for these unregistered/registered IBRs and DERs. CEHE is a TO and does not own IBRs/DERs, therefore, does not have this data. CEHE believes GOs of IBRs should provide the documented information and equipment-specific models since the owner should be aware of the registered/unregistered IBR limitations, parameters, and performance information for their IBR equipment. In addition, unregistered/registered DERs are not modeled at transmission level in dynamic studies.

CEHE has additional concerns with scope objective four of the SAR. Even when unregistered DERs are modeled, it is not clear how a TP will be able to create a dynamic model for these unregistered IBRs/DERs.

Likes 0	
Dislikes 0	

Response	
Scott Thompson - PNM Resources - 3,5 - WECC	
Answer	No
Document Name	
Comment	
PNM supports the comments as well as recommendatioins with EEI.	
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 and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports comments as submitted by CenterPoint Energy Houston Electric, LLC (CEHE).	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	No
Document Name	2022-02_SAR_Unofficial_Comment_Form_05172024_ITC.docx
Comment	
See attached file, as copying from the unofficial comment form and trying to paste in SBS system would not account for strikethroughs.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2022-02 IBR SAR	
Answer	No
Document Name	2022-02_SAR_Unofficial_Comment_Form_IRC SRC_06-24-24_FINAL.docx
Comment	

The **ISO/RTO Council (IRC) Standards Review Committee (SRC)[1]** is concerned that the SAR does not appear to align with NERC's Dynamic Modeling Recommendations whitepaper (see Figure 1).[2]

Example #1

· While the SAR (bottom of page 2) states that: "*NERC Modeling Guidance states that additional model types, namely manufacturer-specific user-written models, must be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance."*

· NERC's Dynamic Modeling Recommendations whitepaper, Figure 1 illustrates that both "**Recommended User Defined Models**" *and* "**Benchmarked (against UDM or EMT) Library Models Recommended**" can be used for "**Local Reliability Studies**" and "**Plant Interconnection Studies.**"

· The SAR also appears to contain conflicts within itself. As noted above, the SAR (bottom of page 2) and the below bullet (from page 4, section 1.c.ii.) are contradictory. Page 2 of the SAR indicates only one type of model "*manufacturer-specific user-written models must be used*" whereas page 4 of the SAR indicates that equipment-specific models should be used if generic models are inaccurate. This would seem to indicate that more than one type of model (as indicated by the dark blue and light blue shading) is acceptable.

o SAR (page 4, section 1.c.ii.) states that: *"For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR."*

The SRC requests the SDT align the SAR with the Dynamic Modeling Recommendations whitepaper.

Example #2

Likewise, there appears to be another conflict between NERC's Dynamic Modeling Recommendations whitepaper and the SAR (page 2): "*As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases."* Here again, the whitepaper allows for more flexibility in that Figure 1 illustrates "Recommended User-Defined Models" are also acceptable.

Recommendation:

The SRC recommends the SDT review the language in FERC Order 901, the SAR and NERC's Dynamic Modeling Recommendations whitepaper to ensure alignment across all three (3).

The SRC also has the following comments and concerns regarding the scope of the SAR:

§ Regarding Scope #2.a.iii, the SRC is concerned with the current language as it assumes a relationship among different industry entities that may not actually exist. More specifically, it is unclear how data collection and data validation can be audited and enforced for entities not registered with NERC. If this scope remains, the SRC requests that it be revised to give the PC flexibility in determining unregistered IBR and DER collection based on location and penetration thresholds.

§ Regarding Scope #3, based on the scope assumptions, it is not clear how an inaccurate model would be found and when a CAP would be needed. The SRC recommends revising the scope to include the TO in developing this framework.

§ Regarding Scope #4, the SRC agrees with the scope as written and requests the addition of an additional step: 4d. the transfer of data collected by the DPs and TOs to the PAs, PCs, and TOPs.

The SRC also requests coordination of this SAR and Project across the multiple IBR/Order 901 Projects. Specifically, the SRC requests assurance that SDTs will coordinate among each other.

Additionally, while the SRC agrees that there are benefits to having a standard modeling framework, the SAR is too restrictive in specifying the Model Library. Failure to utilize common models was not a significant factor in the unexpected performance events cited in the SAR. Inaccurate model performance was mostly associated with model parameterization rather than model selection (and in the cases where model selection was the primary issue, it was because a generic model was used instead of an equipment-specific model that may have been better able to reflect the actual performance of the unit). If the Model Library concept is maintained, it needs to include equipment-specific models and/or provide usability specifications for the development of equipment-specific models. Note that two of the cited FERC directives (items 13 and 14 in the SAR) refer to "approved industry" IBR models:

from item 13 "…Reliability Standards that require the use of approved industry IBR models that **accurately** reflect the behavior of all IBRs…" (emphasis added), and

from item 14 "…Reliability Standards that require the use of approved industry generic library IBR models that **accurately** reflect the behavior of IBRs…" (emphasis added).

Both items mention the need for accurate models, but only one mentions generic models. It seems that FERC would prioritize model accuracy over the use of generic models. The SAR should be clear on which path the SDT should pursue. If necessary, NERC should seek clarification from FERC before heading down a path of mandating the use of generic models and creating unnecessary barriers (red tape and documentation requirements) to the use of equipment-specific models.

Finally, the SAR should include a requirement for the drafting team to assign appropriate compliance obligations between model builders and model suppliers (Model Library). Because of the dual paths there could be uncertainty of compliance obligations if an Interconnection-wide case includes a model that is not in the Model Library. The SAR should clarify whether the responsibility rests with the case builders (PC/TP/RC/designee) or the model supplier (TO/GO). A very restrictive requirement as contemplated in the SAR would be difficult for the case builders to comply with because, as a practical matter, base cases need to get created/finalized with the data that is available, and case builders sometimes need to fill in gaps and make assumptions. Sometimes models, including generic models, and parameterization that look reasonable don't initialize properly (despite troubleshooting efforts) and the best and most accurate option to meet a deadline may be to utilize a model that may not be on the approved list.

[1] For purposes of these comments, the IRC SRC includes the following entities: ERCOT, IESO, ISO-NE, MISO, NYISO, PJM and SPP.

{C}[2] Dynamic Modeling Recommendations (nerc.com)

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	No
Document Name	

Comment

Regarding 1.c.i and 1.c.ii as shown below, Generator Owners should standardize equipment and configuration so that PCs and TPs can use industry-approved library models. User models might be used initially but should be migrated over time into standardized models.

c. The Model Library will be consistent with NERC's published Dynamic Modeling Recommendations, primarily:

i. Industry-approved library models are sufficient for use in Interconnection-wide base case creation and interconnection-wide studies;

ii. For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR.

Suggested replacement language is

{C}i. "For interconnection studies, equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR. As the interconnection studies are completed, generator manufacturers should work with power system software vendors to develop industry-approved library models for the equipment.

The existing wording will require obtaining two sets of models and then maintaining cases with two sets of models, potentially indefinitely.

Regarding 3.b.ii and 3.b.iii as shown below, where there are discrepancies between the provided models and equipment performance, Generator Owners should be expected to correct the discrepancy so that the performance matches the models that were provided.

c. Modify MOD-032 to require Generator Owners (GO) and Transmission Owners (TO) to follow the uniform framework developed in Item 2, specifically;

ii. For instance, studied discrepancies between the generic model and performance or the IBR demonstrated during the interconnection process may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

iii. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e. from a post-event analysis) may necessitate usage of an equipment-specific model instead of a generic model from the Model Library.

Suggested replacement language is:

{C}*i. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e. from a post-event analysis) may necessitate the Generator Owner correcting the performance of the facility so that it matches the model provided.*

Authors should also modify the scope to address another FERC Order 901 Directive Assigned to this SAR. For bullet 19,

"Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior)." (P141)

Scope should include defining what it means to "*in the aggregate have a material impact on the Bulk-Power System"* and defining all *"momentary cessation and/or tripping, and all ride through behavior"* or limits thereof.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3, Group Name Exelon	
Answer	No
Document Name	

Comment

NERC plans to set up a “NERC-Approved Model Library” and have PCs/TPs/RCs/TOs/BAs use a “uniform modeling framework”, both huge tasks, it may be difficult if not possible to complete by the 901 deadline

Paragraph 4 of the project scope (see page 5) calls out for TO’s and DP’s to have methods to aggregate unregistered IBR’s. The standards will need to be very clear on how the TOs and DPs can do this or else demonstrating compliance might be difficult.

Paragraph 17 on page 8 also references TO’s needing to provide dynamic data for unregistered IBR’s. This might be even more difficult, An unregistered IBR cannot be compelled to provide data. While such requirements can be added into future interconnection agreeements, TOs will not have the ability to compel currently connected unregistered IBRs to provide data.

Paragraph 24 on page 9 states that NERC will have to determine the appropriate registered entity to provide the data where a registered DP is not involved. Registered Entities will limited in the ability to collect data by the language of existing interconnection agreements.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	

Comment

As explicitly stated, the intent of the uniform framework for data sharing and model development is to ensure all directive of FERC order 901 can be effectively met and all impacted parties/users of the approved models are informed and provided approved models as a result of any requisite changes due to correcting IBR performance. While Constellation agrees with the intent, we are not sure a new standard added is going to be effective in informing and guiding the industry. This will only be burdensome and likely drive confusions as too many processes are being created/revised in short amount of time.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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 would like to offer the following comments: • Additional scope should be limited to model acceptability, not anything to do with exchange of data among entities. There are sufficient requirements to allow TPs, PCs, RCs, BAs, TOPs to obtain/exchange all data that is necessary through MOD-032, TOP-003, IRO-10 data spec requirements. • Only MOD-032 should be modified to require TPs/PCs to incorporate acceptable models (since it is a data spec and modeling standard) • Any additional modification should incorporate significant flexibility in the operational planning models vs. planning models as they are very different and used for different purposes. • Clarify intent of using registered modeling designee.	
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	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

From BPA's perspective, it appears that Project 2024-01's objective is to align the definitions of GO/GOP so they are required to provide models for "registered IBR" down to the 20MW threshold. Similarly, for unregistered-IBR and IBR-DER, the best practice to collect 'good' modeling data is if the entity that has knowledge of the generation is submitting the data. The DP/TO are the frontline entities that would have this data. Going up the NERC Compliance Registry Criteria hierarchy (DP->TO->TP->PC, etc.) will not hold much value as the TP and PC won't have the knowledge needed to produce good models.

BPA believes DPs and TOs will need to register under NERC's Compliance Registry so the PC can obtain accurate models. BPA suggests that a minimum threshold for the cumulative individual or DER inverter-based resources within an area be established that possibly determines DP (and/or TO) registration. BPA believes this would define a baseline and would also require those DP/TO entities to register when their managed areas exceed that baseline. Accurate models will be dependent on what is required of the DP/TO. If the DP/TO entities are registered, potential future modifications to MOD-032, TPL-001, or others, would be more effective.

Likes 0	
Dislikes 0	

Response

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

The SAR appears open-ended in terms of proposed revisions, detailed descriptions, and overlap with the other two modeling SARs (Project 2020-06 and Project 2021-01) – which are primarily text extracted from FERC Order 901. NERC, the NERC RSTC, the NERC Standards Committee, and industry have tended to avoid creating new standards projects with open-ended SARs as this shows insufficient supporting evidence and background to help a small SDT accomplish its mission. This seems particularly relevant given the massive scale, depth, and breadth of these proposed changes and do not believe this is the most effective/efficient SAR definition to address the directives and reliability risks, as it is unclear what the SARs are actually addressing from a reliability perspective. It also appears there are some FERC directives that are linked to a reliability risk that needs to be mitigated, but between this SAR and the other two it is unclear if they are being addressed or not – these risks should be mitigated between these SARs.

In the Purpose or Goal section, this SAR and the Project 2020-06 SAR both state the projects and SDTs will be a clearing house for the modeling work. It seems having two SARs act as a clearing house for modeling work is not necessary and should be clarified.

In the Project Scope, it is unclear which NERC entities have what roles for each of the IBR categories (registered IBRs, non-registered IBRs, and DERs) applicable to this SAR and the other two modeling related SARs.

In the Detailed Description section, repeating all FERC Order 901 directives in full and then only bolding the specific directives that this SAR addresses is confusing and inefficient. Recommend deleting all unrelated language and only keep the specific directives that this SAR is addressing to add clarity to this SAR.

It seems there has been insufficient attention given to the cost-benefit analysis for this SAR. NERC has simply stated "currently unknown" and "vary based on SDT outcome" and did not provide any additional analysis or consideration for costs and how to minimize such costs across all registered entities involved. The vast proposed revisions will significantly increase costs to registered entities, affecting business operations and costs to consumers. Therefore, more due diligence and consideration should be given to cost across all the proposed standards projects.

Likes 0	
Dislikes 0	

Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	

In addition to the current SAR, the following issues should be addressed:

a) For Scope Item 2d: Generally, the DPs (and perhaps some TOs performing more of an operations function) do not use PSLF or PSSE as their tool for modeling/aggregating unregistered IBR and DER. There may be data collection and aggregation issues if the specifications for the required data is not platform neutral.

b) Consider as to whether non-compliance with proposed model data requirements should be required to be reported to the Regional Entity, instead of relying on the “complaint” process.

c) For Scope Item 4: A large count (although smaller in size) of entities that serve load fall below the criteria to be registered as a DP. There may be gaps in the existing (or potentially modified) including, but not limited to TOP-003 and IRO-010 standards when trying to collect non-BPS data from un-registered entities, or when asking TOs to pass along data relating to non-jurisdictional entities, although these could be enforced via interconnection agreements.

d) The SDT should consider how DER installed at voltages below 60kV (outside of proposed jurisdiction) will be modeled (ie large amounts of aggregated rooftop solar, etc.) to understand if this will just be included in load forecasting or via another method. Alternatively, the generic residential or commercial load models may need modification as well.

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	

The developers of the SAR did not answer the question: Are there alternatives (e.g. guidelines, white papers, alerts, etc.) that have been considered or could meet the objectives? The question should be answered. The answer should paraphrase the following:

Since the directives of FERC Order 901 instruct NERC to develop new or modified standards, there were no other alternatives considered.

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	
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	
Julie Hall - Entergy - 1,3,6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
We noted in our comments on an earlier SAR, which appears to remain unresolved, that a Distribution Provider may not always be the most practical source for the DER modeling data needed by the PC and TP. We recognize that the SDT has allowed for the flexibility of a Transmission Owner to also be a source for DER modeling data in Draft 1. However if the DP or TO is not directly affiliated with the DER owner, would their need to collect the DER model data from the entities that possess it not essentially mirror the PC and TP's need under R1? The DP and TO might need their own requirement(s) to develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures to obtain DER modeling data (potentially from unregistered entities that don't have an obligation to comply with NERC's Reliability Standards) that would subsequently be passed on to the PC and TP. A "DER data entity" could also be added to the applicability section (reference PRC-006-5 for precedent) with a broader range of registered entity options to fulfil that role (e.g., DP, UFLS-Only DP, TO, RP, GO).	
Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the drafting team to consider, if desired.	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Reliability Coordinator is listed twice on Page 10.	
Likes 0	
Dislikes 0	
Response	
Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
We recommend that the SAR drafting team extend the comment period on this SAR and the other two modeling related SARs until after the July 10 NERC Webinar that will inform the industry further about these three SARs and have a question-and-answer period for attendees. This webinar seems like it will be very informative and helpful to the industry in understanding these three SARs, which would further support the comment period and balloting process for getting the SARs approved. There should be a much clearer linkage to the EMT-related NERC projects and EMT modeling requirements in general, which are the best models and studies to evaluated IBR ride-through and other technical performance criteria. While FERC did not call out EMT requirements in Order 901, it did recommend continuing to pursue efforts and those efforts should be closely aligned with this SAR. This SAR and the other two modeling related SARs should also: 1) acknowledge and work towards getting verified and validated modeling throughout the interconnection process from beginning to commissioning and energization. 2) acknowledge and supporting improvements in the dynamic model estimation and aggregation of unregistered IBRs and DERs, which requires significant assumptions to be made. Guidance and technical background should be part of this SAR to support the industry on the assumptions and modeling work that should go into this modeling estimation and aggregation of unregistered IBRs and DERs.	
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	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company asks that the drafting team give consideration to where these requirements could be covered by FAC-001/2.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
NERC needs to find a way to incorporate the intent of this standard into existing/future standards. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	
Document Name	

Comment
Keeping the SAR title consistent with the project name or vice versa would be helpful when several SARs for similar projects are out for comment at the same time.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2022-02 IBR SAR

Answer	
Document Name	2022-02_SAR_Unofficial_Comment_Form_IRC SRC_06-24-24_FINAL.docx

Comment

The SAR states that “[t]he deficiencies within the current state of model quality are well documented,” but then goes on to require only the use of “an approved (standard) library of model types” or models included in a “NERC Approved Model Library.”

With evolving modeling practices, the SRC is concerned that a requirement to only use models that have gone through a NERC approval process would create a bottleneck by potentially delaying the use of more accurate models that are newly developed (perhaps reflecting new technologies) or would result in the use of less accurate models in the name of standardization. The result may very well be less accurate simulation results, which is the opposite of the intent of this SAR. To avoid this result, the SAR should direct the SDT to ensure that the standard clearly provides that any model deemed acceptable by a PC or TP is presumed to be included in the “NERC Approved Model Library” in advance of any formal process.

The SAR states that “[t]his Model Library will be developed and maintained by NERC. Updates on the Model Library development will be coordinated with the Drafting Team.”

This implies that the SDT has an ongoing obligation regarding updates to the model library. The SAR should be revised to clarify whether NERC intends to propose a process for updating the model library that the SDT will evaluate, potentially by soliciting industry comments.

The SAR states “industry-approved library models are sufficient for use in Interconnection-wide base case creation and interconnection-wide studies; ii. For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment-specific models should be used if generic models from the Model Library cannot accurately represent the IBR.”

It is unclear whether “industry approved library models” is synonymous with the “Model library,” and the SRC recommends that the SAR be revised to clarify this point.

Additionally, these statements imply that only generic models will be included in the Model Library and that these are (by default) sufficient for use in Interconnection-wide cases (even if they cannot accurately represent the IBR). In other words, the SAR appears to intentionally allow the use of inaccurate (or even less accurate) models in Interconnection-wide cases. **The SRC recommends that the SAR be revised to require that models accurately represent the IBR. This would allow for the use of a generic model that can accurately represent the IBR for both local studies and Interconnection-wide cases, while ensuring that entities are required to use an equipment-specific model for both local studies and Interconnection-wide cases if that is the only model that can accurately represent the IBR.**

Otherwise, the purpose of creating Interconnection-wide cases, namely, having a common dataset that is used for nearly all local studies, is defeated. Having to replace all of the inaccurate generic models in the local study area for every local study is like re-inventing the wheel for every local study. Further, this creates uncertainties and complications in every local study regarding the determination of the extent to which inaccurate generic

models allowed in the Interconnection-wide cases need to be replaced (recall that in the Odessa event, ride-through failures occurred hundreds of miles away from the fault location).

To help address this, section 3.a of the SAR scope should be revised to read: "GO and TO of IBR must provide models that accurately represent IBR performance (either generic models from the Model Library or equipment-specific models as needed) for interconnection-wide model creation…."

The Model Library (and Interconnection-wide cases) must be open for the inclusion of equipment-specific models (and not just generic models). Otherwise, this SAR is a step backward for modeling accuracy. The Model Library could include usability specifications or requirements for the acceptance of equipment-specific models.

The SAR states that "GO and TO of IBR must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models."

This statement is backwards, as it prioritizes standardization over modeling accuracy. Instead of requiring a justification for the use of an equipment-specific model, the SAR should require a demonstration that a generic model can accurately represent IBR performance before its use is allowed (though equipment-specific models, too, should be subject to a requirement for a demonstration that they accurately represent IBR performance).

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

SPP has concerns about language mentioned in the Standards Authorization Request (SAR) pertaining to the Compliance Registry Criteria. The language suggests that FERC Order 901 should properly align with the revised Compliance Registry Criteria when it comes to the registering of the Inverter Based Resources (IBRs) and Distributed Energy Resources (DERs). However, it is not clear where this alignment takes place. From our perspective, the current posting of the Rules of Procedures (RoP-Appendix 5B Version 7) does not mention the registration and/or definition of the IBR or DER as well as the appropriate entities to register them.

In addition, SPP has a concern about the clarity of the rooftop IBRs being included in the FERC Order 901 efforts. At this point, it is not clear if rooftop IBR will be included in the FERC Order 901 alignment with the revised Compliance Registry Criteria.

Moreover, the SAR mentions modeling efforts and the use of the MOD-032 Standard in reference to data collection. From our perspective, there will be a need to include that data in the modeling process to ensure accuracy for the various analyses results that NERC is requiring applicable entities to conduct.

SPP recommends that NERC staff provide clarity on this topic by including language in the SAR discussing their expectations for all IBRs. Furthermore, it is important for NERC staff to understand that none of the resource issues can be addressed until the MOD-032 data collection project has resolved.

Finally, SPP has concerns about FERC Order directive number seventeen (17) and their expectations of the Generator Owner (GO) and Transmission Owner (TO) sharing dynamic model information for registered and unregistered IBRs. We feel that it will be a difficult task to have appropriate representation in the dynamic models when it comes to unregistered IBRs. Furthermore, the directive mentions addressing momentary cessation and

ride through behavior. At this point, NERC has not resolved their issues with the PRC-024 Standard from a performance perspective. From our observation, it will be difficult to align any FERC Order 901 effort with this directive.

SPP recommends that NERC staff provide clarity on the expectations for the unregistered IBRs as well as coordinating with Project 2020-02 drafting team from a ride through and momentary cessation point of view.

Likes 0	
Dislikes 0	

Response

Christy Thompson - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC

Answer	
Document Name	

Comment

The DT should keep in mind that most entities already use and effectively share generic models for IBRs. While user-written models may be prevalent in interconnection-wide models, correcting this issue does not require the establishment of an entire new process or library. Rather, the DT should consider how to shape careful adjustments to existing standards to achieve the relevant directives of FERC Order 901.

Likes 0	
Dislikes 0	

Response

Julie Hall - Entergy - 1,3,6, Group Name Entergy

Answer	
Document Name	

Comment

1. Will the subsequent SARs on model validation include consideration of comparison of simulation results among generic models used for interconnection-wide base cases and equipment-specific models used for interconnection studies? If so, a process is needed to rectify differences observed in the simulation results among generic vs. equipment-specific models.
2. It is unclear if the recommendation to use equipment-specific models in interconnection studies for all IBRs shall apply to existing IBRs as well as the new IBRs under study. It seems under this scenario PCs and TPs would have to continuously maintain two sets of dynamic modeling files --- one using generic models and one using equipment-specific models. Maintaining and troubleshooting an equipment-specific model dynamic file may become challenging as the number of user-defined models increases given that much of the code is concealed behind a DLL.
3. Item #2 describes the provisions that are associated with new, modified, or changed equipment. This should consider and/or reference provisions already developed regarding the FAC-002 Qualified Change.
4. Related to data exchange of models associated with steady-state, short-circuit, and dynamic conditions, EMT models should be included as well or a reference to the standards that are being considered relating to submission of EMT models for IBRs. However, EMT models for IBR-DER (particularly unregistered) should be precluded. Estimating parameters associated with a DER EMT model would be quite challenging and there are limited references with regards to estimated EMT models, particularly for DER facilities, for which a TO or TP could reference.
5. Item #3.b.i provides an example related to a TP identifying a CAP related to planning criteria violations which may have been triggered by the generic IBR model inaccuracies. A process should be developed which allows the TP/PC to request equipment-specific models and/or updates

to generic models if the TP/PC believes there may be an issue with the model (e.g. protection system settings in the VTGTPA model contradict settings in the REEC high voltage logic Vup/Vdip) and for the GO to provide a response in a timely manner such that the TP/PC can incorporate the updates in their reliability assessments and evaluate the necessity of the CAP.

6. Paragraph 3 of the SAR becomes confusing when noting that unregistered IBRs be considered as a registered IBR (is this the intent?) when identifying assets for the Compliance Registry. If they're unregistered, who, then, would take that ownership (either GO or GOP)? This seems problematic. Several items in the "Requested Information" section discuss this.
7. Subsequently, does #4 then put the onus for any reporting failures (of the data aggregation) of an unregistered IBR on the TO/DP?
8. Entergy has concerns related to obtaining detailed information as specified in item #3 given that the manufacturers treat this information as proprietary in nature.
9. Item 24 in the requested information discusses "materially impact the reliable operations of the BPS". It's unclear what "materially impact" means.

Likes 0	
Dislikes 0	

Response

Michelle Olson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

The Risk, Purpose and Detailed Description should be evaluated to provide concise descriptions without the additional Order 901 language. (see below for example)

In the Project Scope, Item 1a/b/c, the NSRF understands that NERC will be responsible for developing and maintaining the Model Library. However, it is unclear what work activities, if any, the Drafting Team will perform regarding the Model Library. Coordinating Model Library development with the DT is an administrative function that does not require specific DT work activities. Therefore, we recommend removing Items 1a/b/c from the SAR Project Scope section.

Also, we recommend that the NERC-Approved Model Library contain only the acceptable models. Including unacceptable models does not provide value.

In the Project Scope, Item 3, the NSRF recommends using a process similar to that currently used for synchronous generation.

The NSRF does not agree with mixing the modeling data requirements associated with MOD-032 with the data collection requirements of TOP-003 and IRO-010. Data requirements are best handled in a single place, MOD-032. Eliminate references to IRO-010 and TOP-003. Otherwise there is the potential to review many neighboring entity data specs for differing data requirements.

Items 11, 17, 21 and 24 of the Detailed Description are NERC directed tasks and the NSRF believes those activities should be removed from this of this SAR and addressed separately by NERC.

Example:

1. What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

FERC Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements addresses regulatory directives from the NERC Standards Development Work Plan to respond to FERC Order No. 901.

The current paradigm of modeling and data sharing leaves the bulk power system (BPS) at a higher than necessary risk for unexpected and undesired inverter-based resource (IBR) performance. Since 2016, approximately 15,000 MW of IBR have unexpectedly reduced output during NERC categorized disturbance events. None of the IBR facilities involved in these disturbances utilized models that could accurately represent the facility's performance during the disturbance event. These discrepancies between modeled and studied performance when compared to real-world performance are driven by current industry modeling practices and a dependence on generic IBR modeling throughout the lifecycle of the IBR facility.

The current Reliability Standards may not account for the material technological differences between the response of synchronous generation resources and the response of IBRs to the same disturbances on the Bulk-Power System.

2. Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):

This project is intended to establish new or revised Reliability Standards to ensure the usage of a uniform framework for data sharing and model development. This uniform framework is to ensure the directives of Order No. 901 can be effectively met to ensure usage of generic model types for IBR in the Interconnection-wide models.

Current Reliability Standards do not ensure that Bulk-Power System planners and operators have the necessary tools to plan for and reliably integrate IBRs into the Bulk-Power System or to plan for IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk-Power System (IBR-DER). IBRs, individually and in the aggregate, and IBR-DERs in the aggregate can have a material impact on the reliable operation of the Bulk-Power System.

Additionally, the Reliability Standards do not contain performance requirements that are unique to IBRs and are necessary to ensure that IBRs operate in a predictable and reliable manner.

Revisions to data sharing expectations and the creation of a “NERC Approved Model Library” that allows the use of manufacturer-specific models in addition to standard library (generic) models in instances where generic modeling cannot represent the performance of the IBR are necessary to ensure BPS reliability through improvements to the inputs of current study practices.

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

The scope is seeking to modify MOD-032, IRO-010 and TOP-003 – I do not have additional comments.

4. 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]. of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (e.g., research paper) to guide development of the Standard or definition):

As of April 1, 2024, this SAR will address the following FERC Order No. 901 directives, with the scope for this SAR emphasized in **bold** as appropriate:

However, the Project Scope states: “901 directives assigned to this SAR are outlined in the Detailed Description section below. The project scope shall address all those directives…”

There are 26 bulleted FERC directives listed in the Detailed Description. Is the intent of this SAR to address all 26 directives or just directives **17, 24** & **25**?

[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.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 1,3,5,6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation does not have any additional comments for the SAR drafting team to consider.

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. IBR manufacturer-specific user written models are unique to each facility. These models require a significant investment of time and money to develop/test/validate and therefore sharing of such OEM proprietary models is unlikely. The NAGF proposes that NERC consider developing model specifications as a method for determining the most appropriate models for industry to use. b. The NAGF notes that current IBR models do not accurately represent momentary cessation/tripping and ride through behavior.	
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 SAR.	
Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	
Document Name	
Comment	
Manufacturer-specific models, if allowed or required by any portion of the revised NERC standards, must be provided by OEMs for industry use without restrictions on sharing of these models with TPs, TOs, PCs, and GOs.	

Also, how will the Model Library be developed and maintained by NERC? Will the models be freely shared with software tool developers (GE, Siemens/PTI, Manitoba Hydro, PGSTech, ASPEN, Powertech, etc.)? How will NERC require inverter manufacturers provide the necessary information to implement models in the industry software tools before such inverters are connected to the grid going forward?

Some effort should be made to require automated model benchmark validation testing with a GO's specified parameters for their particular facility be provided within the industry software tools. This benchmark validation testing could be provided by the software tool vendors or by the NERC group responsible for the Model Library.

Likes 0	
Dislikes 0	

Response

Hayden Maples - 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 2

Likes 0	
Dislikes 0	

Response

Greg Sorenson - ReliabilityFirst - 10 - RF

Answer	
Document Name	

Comment

o This SAR process is likely missing a Requirements Definition phase that captures all the specifications that are needed to run analysis (i.e. TPL-001), and then work backwards to determine how to model the DER. For example, certain needed studies may need different data:

a) To run a study where you want to see system performance when solar drops off and EV charging increases due to consumer behavior, it is likely that a time-of-day case is needed for hour-ending 19:00 vice peak hour.

b) To run a study showing the dynamic performance of IBR solar generation at system peak conditions, it is likely needed to have a case with increased dispatch of solar generation with either corresponding DER_A or Composite Load Models that include DER included in the dynamic data sets such as DYD in PSLF or DYR in PSSE.

The concept of modeling IBRs is to have extremely accurate data/models. There is no guidance for how to “make-up” an aggregate IBR model. Even in EMT studies, accuracy suffers when you try to “aggregate” modeling data from several different equipment manufacturers into one “blended” model. How can the framework account for the need to aggregate and/or blend data and still meet the accuracy needs of the modeling/analysis process? Are changes to the standard load model needed to allow for percentages of rooftop solar to be added on a substation level?	
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 - 5,6	
Answer	
Document Name	
Comment	
NERC needs to find a way to incorporate the intent of this standard into existing/future standards. m	
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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
3.b.ii: Clarify whether interconnection process refers to the Interconnection System Impact Study, Commissioning Phase, or other? Consider in the implementation of effective dates the requirement of dependency between requirements. For example, if GO needs to provide models and the TP and TOP need to use the models, then the GO requirement should become effective prior to the TP/TOP requirements, allowing the TP/TOP time to incorporate models in their process. Or, if the RC needs to build a methodology and the TOP needs to implement the methodology, the RC requirement should be effective prior to the TOP requirement, allowing the TOP time to implement the updated methodology.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
WECC suggests that the SAR be reviewed and checked for capitalization of “Interconnection” as it varies throughout SAR and should be capitalized consistently.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	
Document Name	
Comment	

The Risk, Purpose and Detailed Description should be evaluated to provide concise descriptions without the additional Order 901 language.

Example:

1. What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

FERC Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements addresses regulatory directives from the NERC Standards Development Work Plan to respond to FERC Order No. 901.

The current paradigm of modeling and data sharing leaves the bulk power system (BPS) at a higher than necessary risk for unexpected and undesired inverter-based resource (IBR) performance. Since 2016, approximately 15,000 MW of IBR have unexpectedly reduced output during NERC categorized disturbance events. None of the IBR facilities involved in these disturbances utilized models that could accurately represent the facility's performance during the disturbance event. These discrepancies between modeled and studied performance when compared to real-world performance are driven by current industry modeling practices and a dependence on generic IBR modeling throughout the lifecycle of the IBR facility.

The current Reliability Standards may not account for the material technological differences between the response of synchronous generation resources and the response of IBRs to the same disturbances on the Bulk-Power System.

2. Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):

This project is intended to establish new or revised Reliability Standards to ensure the usage of a uniform framework for data sharing and model development. This uniform framework is to ensure the directives of Order No. 901 can be effectively met to ensure usage of generic model types for IBR in the Interconnection-wide models.

Current Reliability Standards do not ensure that Bulk-Power System planners and operators have the necessary tools to plan for and reliably integrate IBRs into the Bulk-Power System or to plan for IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk-Power System (IBR-DER). IBRs, individually and in the aggregate, and IBR-DERs in the aggregate can have a material impact on the reliable operation of the Bulk-Power System.

Additionally, , the Reliability Standards do not contain performance requirements that are unique to IBRs and are necessary to ensure that IBRs operate in a predictable and reliable manner.

Revisions to data sharing expectations and the creation of a "NERC Approved Model Library" that allows the use of manufacturer-specific models in addition to standard library (generic) models in instances where generic modeling cannot represent the performance of the IBR are necessary to ensure BPS reliability through improvements to the inputs of current study practices.

*3. 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{C}**[1]**{C} of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (e.g., research paper) to guide development of the Standard or definition):*

As of April 1, 2024, this SAR will address the following FERC Order No. 901 directives, with the scope for this SAR emphasized in **bold** as appropriate:

However, the Project Scope states: "901 directives assigned to this SAR are outlined in the Detailed Description section below. The project scope shall address all those directives…"

There are 26 bulleted FERC directives listed in the Detailed Description. Is the intent of this SAR to address all 26 directives or just directives **17, 24** & **25**?	
Likes 0	
Dislikes 0	
Response	

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022
45-day formal comment period with ballot	5/31/2023 – 7/14/2023
45-day formal additional comment period with ballot	6/1/2023 – 7/17/2023
45-day formal comment period with additional ballot	10/6/2023 – 11/20/2023

Anticipated Actions	Date
45-day formal comment period with additional ballot	8/27/2024 – 10/10/2024
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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system, including those connected behind the meter of an end use customer, that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System.

- Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Generator Owner

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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 applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 the 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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to	Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed	Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				upon by the notifying Planning Coordinator or Transmission Planner).	upon by the notifying Planning Coordinator or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-2 – ATTACHMENT 1:

Data Reporting Requirements

The table below indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [DP] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[2] [DP] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, DP]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Distribution Provider (DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc.) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	9. DC system models [TO] 10. Aggregate Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS[4] [DP] 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
9. Aggregate Distributed Energy Resource (DER) data[4] [DP] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.) d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes. 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

[4] For purposes of this item, the Distribution Provider to which DER is connected is responsible for reporting DER data, generally through coordination with the Transmission Owner, in accordance with PC/TP modeling data requirements and data reporting procedures developed under Requirement R1. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022
45-day formal ~~or informal~~ comment period with ballot	~~6~~5/31/2023 – 7/~~17~~14/2023
45-day formal additional comment period with ballot	6/1/2023 – 7/17/2023
45-day formal comment period with additional ballot	10/6/2023 – 11/20/2023

Anticipated Actions	Date
~~45-day formal or informal comment period with ballot~~	~~6/1/2023 – 7/17/2023~~
~~45-day formal or informal comment period with additional ballot~~	~~10/6/2023 – 11/20/2023~~
45-day formal comment period with additional ballot~~XX-day final ballot~~	8/27/2024 – 10/10/2024
10-day final ballot	TBD
Board adoption	~~12/12/2023~~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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system, including those connected behind the meter of an end use customer, that are capable of providing Real Power in non-isolated parallel operation with the Bulk ~~Electric~~ Power System.

- Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria~~not the NERC registered entity~~.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   ~~**4.1.2**~~**4.1.3** Generator Owner

   ~~**4.1.3 Distribution Provider**~~

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

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

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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 applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 the 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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to	Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or	and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, Distribution Provider, Resource Planner, Transmission Owner, or

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed	Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				upon by the notifying Planning Coordinator or Transmission Planner).	upon by the notifying Planning Coordinator or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
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MOD-032-2 – ATTACHMENT 1:

Data Reporting Requirements

The table below~~,~~ indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. ~~-~~Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases.~~–~~ A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions.~~-~~ Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [DP] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand~~2~~ [DP] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, DP]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Distribution Provider (DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. ~~-~~A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions.~~-~~ Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc.) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	9. DC system models [TO] 10. Aggregate- Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS[4] [DP~~, TO where DER is directly connected to the TO system and not through a DP~~] 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions.~~-~~ Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
9. Aggregate Distributed Energy Resource (DER) data[4] [DP~~, TO where DER is directly connected to the TO system and not through a DP~~].[5] a. Location (bus from item 1) b. Real power capability c. ~~Generator~~ DER type (solar, battery, diesel generator, etc.) d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes. 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

[4] ~~The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.~~For purposes of this item, the Distribution Provider to which DER is connected is responsible for reporting DER data, generally through coordination with the Transmission Owner, in accordance with PC/TP modeling data requirements and data reporting procedures developed under Requirement R1.~~-~~ The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.

[5] ~~Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.~~

Standard Development Timeline

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

Description of Current Draft

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/19/2022
SAR posted for comment	2/1/2022 – 3/02/2022
45-day formal ~~or informal~~ comment period with ballot	~~6~~5/~~3~~1/2023 – 7/1~~7~~4/2023
45-day formal additional comment period with ballot	6/1/2023 – 7/17/2023
45-day formal comment period with additional ballot	10/6/2023 – 11/20/2023

Anticipated Actions	Date
~~45-day formal or informal comment period with ballot~~	~~6/1/2023 – 7/17/2023~~
~~45-day formal or informal comment period with additional ballot~~	~~10~~9/~~6~~1/2023 ~~–~~ ~~10~~11/~~15~~20/~~2023~~
45-day formal comment period with additional ballot~~XX-day final ballot~~	8/27/2024-10/10/2024
10-day final ballot	TBD
Board adoption	~~12/12/2023~~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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system, including those connected behind the meter of an end use customer, that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System.

- Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria.

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   ~~4.1.2~~4.1.3 Generator Owner

   ~~4.1.3~~4.1.4 ~~Load Serving Entity~~

   ~~4.1.4~~4.1.5 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.~~

   ~~4.1.5~~4.1.6 Resource Planner

   ~~4.1.6~~4.1.7 Transmission Owner

   ~~4.1.7~~4.1.8 Transmission Planner

   ~~4.1.8~~4.1.9 Transmission Service Provider

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

   ~~MOD-032-21, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-21, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a~~

jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. ~~-~~For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying

Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

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.

~~"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. "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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 ~~Assessment~~ Enforcement Program~~Processes~~: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

~~**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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required

						components specified in Requirement R1.
R2	**Long-term Planning**	**Medium**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state,

			Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission	Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short	Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short	dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data

			Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.

R3	**Long-term Planning**	**Lower**	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less	The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3~~4~~ within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

			or Transmission Planner).	than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4	**Long-term Planning**	**Medium**	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

~~None.~~

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

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

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

reduce the quantity of MOD standards;

add short circuit data as a requirement to the MOD standards; and

supply data and models:

add requirement identifying who provides and who receives data;

identify acceptability;

standard format;

how to deal with new technologies (user written models if no standard model exists); and

a. shareability.
b. These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
c. The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
d. Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.
e. Rationale for R2:
f. This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."
g. **Rationale for R3:**
h. In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.
i. This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and

cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts."* (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection-wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0,

			MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	TBD	Revised under Project 2022-02

MOD-032-~~01~~ 2 – ATTACHMENT 1:

Data Reporting Requirements

The table~~,~~ below~~,~~ indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. ~~-~~Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. ~~–~~A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. ~~-~~Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions.~~-~~ Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [~~LSE~~DP] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[2] [~~LSE~~DP] 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), ~~Load Serving Entity~~Distribution Provider (~~LSE~~DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A ~~Load Serving Entity~~Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions.~~-~~ Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status*	8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC system models [TO] 10. Aggregate Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS ~~[DP, TO where DER is directly connected to the TO system and not through a DP]~~ ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	c. Zero Sequence Data 2. Mutual Line Impedance Data~~-~~ [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
9. Aggregate Distributed Energy Resource (DER) data[4] [DP, TO where DER is directly connected to the TO system and not through a DP] [5] a. Location (bus from item 1) b. Real power capability c. DERGenerator type (solar, battery, diesel generator, etc.) d. DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes. 9.10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSEDP, TO, TSP]		

[4] The joint PC/TP modeling data requirements and reporting procedures developed per R1 will specify data flow processes and the required level of aggregation. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.

[5] Where DER is connected to an unregistered Distribution Provider, the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information. An unregistered Distribution Provider is an unregistered entity meeting the NERC Glossary of Terms definition of Distribution Provider. This footnote is also applicable to item 10 under the "dynamics" column.

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Implementation Plan

Project 2022-02 Uniform Modeling Framework for IBR

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Owner
- Planning Coordinator
- Resource Planner
- Transmission Owner
- Transmission Planner
- Transmission Service Provider

NERC Glossary of Terms

This section includes a newly defined term used in the NERC Reliability Standard. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, the defined term will be removed from the individual standard and added to the Glossary.

Proposed New Definition:
Distributed Energy Resource (DER):

Generators and energy storage technologies connected to the Distribution Provider's system, including those connected behind the meter of an end use customer, that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System.

- Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria.

Background

As the penetration of distributed energy resources (DERs) continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Proposed Reliability Standard MOD-032-2 replaces the Load-Serving Entity as an applicable entity with the Distribution Provider and updates Attachment 1: Data Reporting Requirements with data specific to DERs.

General Considerations

In developing this implementation plan, the drafting team (DT) considered the time that would be necessary to develop data requirements and reporting procedures for data related to DERs, including identifying the proper reporting entity. The DT also considered that the standard would become applicable to the Distribution Provider (DP) for the first time. Transmission Owners (TOs) and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource 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 MOD-032-2

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

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date

the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4
Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised PC/TP data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Definition – Distributed Energy Resource (DER)
Where approval by an applicable governmental authority is required, the definition of DER shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1
Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance Dates

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised PC/TP data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Entities shall continue to comply with Requirements R2, R3, and R4 related to PC/TP data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032-2.

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Implementation Plan

Project 2022-02 Uniform Modeling Framework for IBR~~2022-02 Modifications to TPL-001 and MOD-032 Reliability Standard MOD-032-2~~

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Owner
- ~~Distribution Provider~~
- Planning Coordinator
- Resource Planner
- Transmission Owner
- Transmission Planner
- Transmission Service Provider

NERC Glossary of Terms

This section includes a newly defined term used in the NERC Reliability Standard. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, the~~se~~ defined term~~s~~ will be removed from the individual standard and added to the Glossary.

Proposed New Definition~~(s)~~:
Distributed Energy Resource (DER):

Generators and energy storage technologies connected to the Distribution Provider's system, including those connected behind the meter of an end use customer, that are capable of providing Real Power in non-isolated parallel operation with the Bulk -Power System.

- Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria ~~not the NERC registered entity~~.

Background

As the penetration of distributed energy resources (DERs) continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Proposed Reliability Standard MOD-032-2 replaces the Load-Serving Entity as an applicable entity with the Distribution Provider and updates Attachment 1: Data Reporting Requirements with data specific to DERs.

General Considerations

In developing this implementation plan, the ~~standard~~ drafting team (DT) considered the time that would be necessary to develop data requirements and reporting procedures for data related to DERs, including identifying the proper reporting entity. The ~~standard drafting team~~DT also considered that the standard would become applicable to the Distribution Provider (DP) for the first time. -Transmission Owners (TOs)~~s~~ and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. -In summary, this would give a full 36 months from FERC approval until data is required to be reported.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource 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 MOD-032-2

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

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date

the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4
Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised ~~Planning Coordinator~~PC/~~Transmission Planner~~TP data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Definition – Distributed Energy Resource (DER)
Where approval by an applicable governmental authority is required, the definition of ~~Distributed Energy Resource (~~DER~~)~~ shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1
Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance Dates

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised ~~Planning Coordinator~~PC/~~Transmission Planner~~TP data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Entities shall continue to comply with Requirements R2, R3, and R4 related to ~~Planning Coordinator~~PC/~~Transmission Planner~~TP data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032-2.

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Unofficial Comment Form

Project 2022-02 Uniform Modeling Framework for IBR

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-02 Uniform Modeling Framework for IBR** by **8 p.m. Eastern, Thursday, October 10, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Laura Anderson (via email), or at 404-782-1870.

Background Information

Prior to FERC Order No. 901, Project 2022-02 was intended to address multiple Standard Authorization Requests (SARs) related to transmission planning and modeling data and analysis (MOD-032-1 Data for Power System Modeling and Analysis SAR from the NERC System Planning Impacts by the Distributed Energy Resources Working Group (SPIDERWG); TPL-001-5.1 Transmission System Planning Performance Requirements SAR from NERC Inverter-Based Resource Performance Working Group (IRPWG); and TPL-001-5.1 Transmission System Planning Performance Requirements SAR from the SPIDERWG).

The Project 2022-02 Drafting Team (DT) decided to break this project into two phases since there are two Reliability Standards involved and the project scopes are quite different. Phase I addresses MOD-032-1 in data collection and Phase II was intended to address TPL-001-5.1 in the accuracy of transmission system planning assessments. **This posting affects Phase I of the project for proposed Reliability Standard MOD-032-2 and does not contemplate the SAR related to FERC Order No. 901; the Milestone 3, Part 1 posted for industry comments May 17 – June 24, 2024.**

Draft 3 relationship to FERC Order No. 901

Around the time that Draft 3 of proposed Reliability Standard MOD-032-2 was prepared, NERC incorporated FERC Order No. 901, Milestone 3, Part 1 into the current Project 2022-02, expanding the scope of this project to include a uniform modeling framework for IBR and elevating the project to high priority. Given that the DT already modified Draft 3 of proposed Reliability Standard MOD-032-2 in response to Industry comments, and that industry need for DER data exchange continues to exist, this Draft 3 of proposed Reliability Standard MOD-032-2 is being posted for a 45-day comment period with 10-day ballot.

Additional changes to MOD-032 may be needed based on the proposed SAR resulting from FERC Order No. 901, Milestone 3, Part 1 and will be considered as part of the Project 2022-02 workplan once the SAR and workplan have been finalized.

Proposed Distributed Energy Resources (DER) definition changes

As included in the SAR, a DER definition is proposed that is suitable for application across NERC standards (i.e., definition is not specific to MOD-032). Based on industry comment, the DT suggested redlines to clarify that DER includes behind-the-meter resources. Further, the DT proposed a clarification to the term

"Distribution Provider" (DP) to point to the NERC Glossary of Terms definition more clearly, rather than the NERC registration criteria. The Technical Rationale has additional information on the proposed DER definition.

"Pass through" requirement removed

The previous Footnotes 4 and 5 were consolidated to remove any “pass through” requirement and to clarify that the DP is the responsible entity for reporting DER data under currently available entity registration, while recognizing that DER data collection efforts may generally involve DP and Transmission Owner (TO) coordination.

Questions

1. Given the explanation in the Technical Rationale and responses to industry comments, do you agree with the proposed definition for DER? If you do not agree, please suggest modifications to improve the definition.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree that the modifications for the proposed reliability standard address the scope of the SAR, modifications to MOD-032-1, in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

   ☐ Yes
   ☐ No

   Comments:

3. Given the explanation added in the Implementation Plan and in response to industry comments, do you agree with the Implementation Plan for proposed Reliability Standard MOD-032-2?

   ☐ Yes
   ☐ No

4. 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 2022-02 Modifications to MOD-032-2

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-032-2. 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 DT 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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R1

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R2

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R3

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

Project 2022-02 Modifications to MOD-032-2

This document provides the ~~standard~~ drafting team's (~~S~~DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in MOD-032-2. 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 ~~S~~DT 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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R1

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R2

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R3

"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2.

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

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Technical Rationale for Reliability Standard MOD-032-2

August 2024

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. Items in Attachment 1 that were previously required to be provided by the LSE are now required to be provided by the DP. It is recognized that some distribution facilities do not have an associated DP that meets the NERC registration criteria, but it should be clear that compliance obligations can only be imposed on NERC-registered entities listed in the Applicability Section; use of the DP term within proposed Reliability Standard MOD-032-2 should be understood to refer to an entity meeting the NERC registration criteria, unless otherwise specified.

The Drafting Team (DT) has concerns that there may be challenges in collecting data for distributed energy resources (DER) connected to unregistered entities. Draft 1 of proposed Reliability Standard MOD-032-2 proposed to assign this data obligation to the Transmission Owner (TO) or DP, but based on industry comments, this may place an unreasonable compliance risk on the TO/DP because any unregistered entities that connect DER to their systems have no compliance obligation to provide data to the TO/DP. As such, the DT recommends that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would unnecessarily delay the implementation of DER data requirements. The DT believes there is value in moving forward with MOD-032-2, as it does provide substantial improvement with respect to ensuring DER data is available for inclusion in Planning Coordinator (PC) and Transmission Planner (TP) studies. The DT considered adding “UFLS-Only Distribution Provider” to MOD-032-2 applicability to reduce (but not necessarily eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, adding UFLS-Only Distribution Provider to the applicability would not be appropriate at this time.

Additionally, the DT reviewed the dual applicability to PA and PC and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria is updated to use only a single term. The posted “Appendix 5B: Statement of Compliance Registry Criteria,” dated January 19, 2021, still uses both terms and, arguably, the PA term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the DT excluded the explanatory language from MOD-032-2 Applicability Section.

Rationale for Distributed Energy Resource (DER) Definition

The DT considered various DER definitions utilized in the industry and discussed in the SPIDERWG Terms and Definitions Working Document, including the six other definitions described in Appendix D which were not adopted by SPIDERWG. Through this review, the DT determined each of these seven definitions required or would benefit from refinement to be most suitable for application in MOD-032 and future reliability standards more broadly.

The DT consensus is that the proposed definition aligns with the intent of the SPIDERWG working definition for DER (which explicitly excludes demand response) and clarifies what is in scope and out of scope with respect to where DER is connected (rather than the technology type). Utilizing the existing NERC definition for DP and the associated area of responsibility aligns with the scope of DER data collection and modeling activities and provides clarity for the industry to aid in gathering this information. It should be clear that MOD-032-2 applicability and compliance obligations refer to NERC-registered DPs; the use of the DP term in the DER definition does not in itself imply any compliance obligation.

Below is a summary of the rationale for the DT departing from each of the seven definitions when proposing a new DER definition.

SPIDERWG definition

After considering the SPIDERWG definition, the DT determined it provided a useful foundation, but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term 1) included transient types of DER power beyond generation and storage; 2) pointed to a SPIDERWG-specific defined term for “distribution systems”; and 3) included sources of back-up power that would have no potential grid impacts.

The DT chose to refer to generator and storage technologies specifically, rather than use the SPIDERWG language of “source,” to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.) DER can use various technologies including synchronous machines, induction machines, and power inverters/converters (i.e., IBR). Different types of DER can utilize a wide range of energy sources including, but not limited to, natural gas, diesel, hydro, storage, wind, and solar. Further, the DT proposed definition uses “connected to the Distribution Provider’s system” to avoid ambiguities associated with a unique definition of “distribution system” as was required by the SPIDERWG term. The NERC Glossary of Terms definition for DP[1] notes that the DP is defined by providing the distribution function (this includes entities that may not satisfy the NERC registration criteria). Additionally, the DT intention was to ensure that the scope included facilities “connected behind the meter of an end use customer” that may export Real Power to the power system or offset Real Power load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load.

[1] NERC Glossary of Terms, Updated March 2023. Distribution Provider definition is: “Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.”

The DT included the language "in non-isolated parallel operation with the Bulk Electric System" to indicate that DER with potential Bulk Electric System (BES) reliability impacts are those that have electrical connectivity to the BES. The DT intentionally avoided the term “directly connected” to differentiate electrical connectivity from an electrical connection point. Resources that are only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BES and, therefore, are not of interest from a BES-reliability perspective. The DT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry.

IEEE 1547-2018
The DT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the three issues identified above. The DT incorporated the explicit reference to “generation and storage” aspect of the IEEE definition. Further, the IEEE concept of “capable of exporting active power to an EPS” was used to inform the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the DT definition.

At the same time, the DT did not view the IEEE definition as suitable for the DT’s intended use as written. The IEEE term qualifies the DER connection point as “not directly connected to a bulk power system” which the DT viewed as potentially ambiguous. Instead, the DT opted for the “connected to the DP’s system” language to point to a NERC defined term and concept. The DT considered if it was necessary to define “supplemental DER devices” as part of the DER definition and determined this nuance is not needed for a DER definition for inclusion in the NERC Glossary of Terms.

Federal Energy Regulatory Commission (FERC) Energy Primer
The DT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability planning use cases, the DT and SPIDERWG definitions target sources of electric power, with the DT narrowing this definition to be only sources “capable of providing Real Rower.” After considering the FERC definition, the DT determined it was not suitable for the intended use.

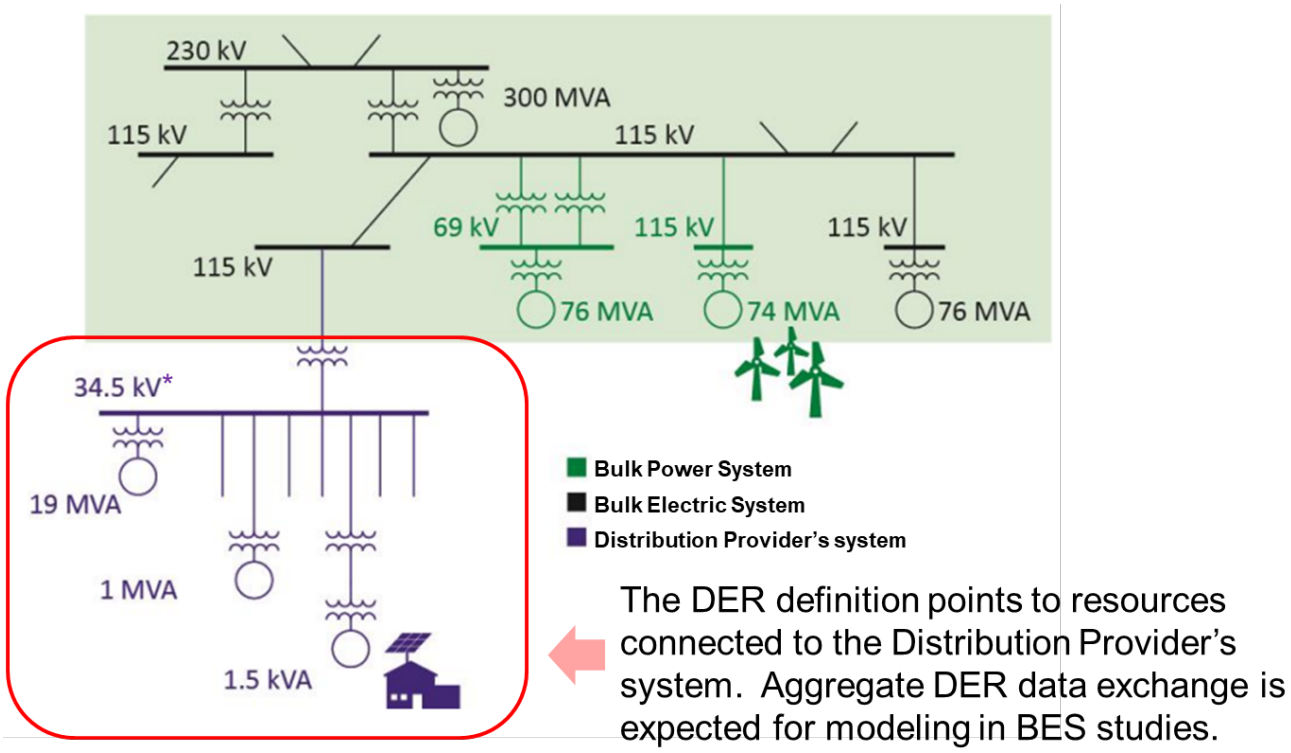
National Association of Regulatory Utility Commissions (NARUC)
NARUC’s definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the DT concluded it is too broad. After considering the NARUC definition, the DT determined it was not suitable for the intended use.

NERC DERTF
The NERC DERTF definition uses the language “resource on the distribution system that produces electricity” which appears to exclude distributed energy storage, a technology necessary for inclusion in the DT definition. Further, the NERC DERTF definition defines DER as anything “not otherwise included in the formal NERC definition of the Bulk Electric system” which the DT views as ambiguous and overly broad. After considering the NERC DERTF definition, the DT determined it was not suitable for the intended application.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be based on California legislation and includes energy efficiency, EVs, and demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the DT's use. After considering the CPUC definition, the DT determined it was not suitable for the intended application.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition to exclude a large portion of DER (i.e. retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study. After considering the NYISO definition, the DT determined it was not suitable for the intended application.

Figure 1 below provides a graphic illustration of the DER definition and the intended scope of facilities that would fall under the proposed definition. Figure 2 below shows that the proposed DER and IBR definitions are compatible, but distinct. Some resources may be classified as DER, but not IBR; some resources may be classified as IBR, but not DER; some resources may be classified as both DER and IBR. Note that in Figure 2, "distribution-connected" is shorthand for connected to the DP's system and "bulk system-connected" refers to resources connected to the transmission system.



*Note: The Distribution Provider's system is not defined by voltage level but rather by function.

Figure 1: DER Definition Illustration

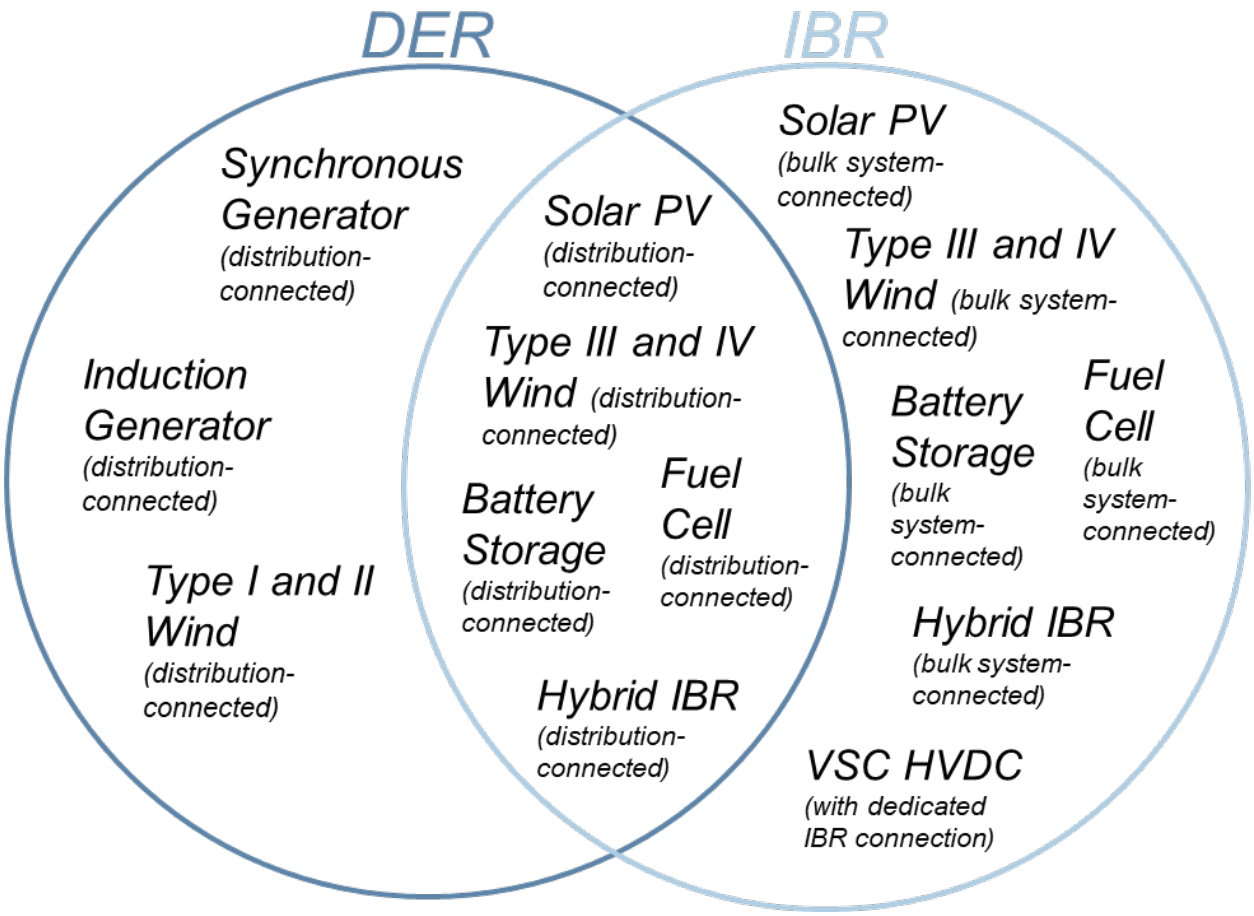


Figure 2: DER and IBR Definition Compatibility

Rationale for Modifications to Attachment 1

MOD-032-2 Attachment 1: Data Reporting Requirements was updated with data specific to DERs. The intent is that all relevant DER data including both utility scale facilities (commonly referred to as U-DER) and smaller behind-the-meter facilities (commonly referred to as R-DER) be available and represented in models of the interconnected transmission system consistent with the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum amount of information expected to be needed to reasonably represent DER in transmission system models. It is expected that aggregate DER (rather than individual DER facilities) would be represented in most PC/TP study models. In Draft 3, the word "aggregate" was specifically added to Attachment 1 to clarify this point based on industry comments. However, Requirement R1 provides the PC/TP great flexibility in developing data requirements and reporting procedures that align with local practices and needs, so long as they include the items listed in the Requirement R1 Parts.

The PC/TP may have access to sufficient data for modeling certain DER through alternative means (e.g., direct registration of DER in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data, but care will be needed to ensure DER is not double counted. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DER that are excluded from the DP/TO obligation for providing DER modeling data. This

in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its PC and TP in Requirement R1.

The DT intentionally maintained flexible language as to whether the underlying DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP/TO applying a combination of approaches to source the data. The PC/TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

The DT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with the required DER data are only presented in the "steady state" column (though arguably such data is also relevant to "dynamics" and/or "short circuit"). The DT concluded that this was appropriate and consistent with other "dynamics" line items such as "Wind Turbine Data" and "Photovoltaic systems" that are listed without detailed sub-bullets. Drastically altering the structure of Attachment 1 or explicitly adding DER data to the "short circuit" column was beyond the scope of the Project 2022-02 SAR. However, the PC or TP is not restricted from requiring any needed short circuit data in their joint modeling data requirements and reporting procedures developed per Requirement R1.

It should be noted that the modifications do not make DER a BES facility subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in Interconnection-wide cases. There are already existing requirements for DPs (or TOs) to provide information about load connected to their systems. Like load, DER is not generally considered to be a BES facility. However, BES reliability assessments require an accurate representation of both aggregate load and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient DER data is available to the PC/TP so that appropriate DER representations can be included in their BES reliability assessments.

- **Inferring DER Capabilities**

As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DER may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DER installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate ride-through characteristic representation for DER in that area could be inferred by the in-service date of the DER. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

- **Inclusion of Data Related to DER Subject to Trip by UFLS and/or UVLS**

There is a reliability need for the DP/TO to convey this information to the PC/TP. As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DER subject to each UVLS/UFLS tripping stage should be identified.

- **Inclusion of Aggregate Demand Clarification**

Footnote 2 was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DER is not consistent with a modeling framework that explicitly represents DER.

- **Footnote 4**

Footnote 4 was clarified and Footnote 5 from the previous draft was removed from Attachment 1 to make it clear that the functional entity that is responsible for reporting DER data under the currently available registered entities is the DP. Previous references to the TO as a responsible DER entity were removed, but the clarified footnote still states and recognizes that DER data collection efforts may generally involve DP and TO coordination. The DT continues to recognize that there are situations where DER is connected to an "unregistered Distribution Provider," instead of a DP or TO, and that it is still an appropriate aim to collect this data. However, in agreement with industry comments, references to data collection efforts or passing through data by the DP/TO from these unregistered entities was removed from the standard language as it could add compliance risk on the DP/TO without any compliance obligation on the unregistered entities. The DT believes that there is great value in moving forward with the standard with the registered DP as the responsible entity for DER data as this will vastly improve the amount of data that is available to the TP/PC.

Where an unregistered DP (an entity not meeting the NERC registration criteria) is interconnected to the system of a registered entity (DP or TO), the DP/TO should coordinate with the unregistered DP to ensure the availability of information associated with DER that may be connected to the unregistered DP's system. This effort would be considered as a best practice, even if not specifically required by the MOD-032 Reliability Standard. FERC Order No. 901 addresses this issue of data collection for DERs that do not have an associated registered entity and directs future efforts to determine appropriate responsible registered entities, but the DT believes that this currently falls outside of the scope of this SAR and will be addressed in the new SAR related to FERC Order No. 901, Milestone 3, Part 1. In the interim, FERC Order No. 901 also describes a process where this data is unavailable and should instead be estimated and the limitations of data availability should be documented.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Technical Rationale for Reliability Standard MOD-032-2

~~October 2023~~August 2024

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. ~~-~~Items in Attachment 1 that were previously required to be provided by the LSE are now required to be provided by the DP. ~~-~~It is recognized that some distribution facilities do not have an associated DP that meets the NERC registration criteria~~. It is expected that TOs (or registered DPs) will need to coordinate with the owners of distribution facilities that do not have an associated NERC registered DP to ensure the availability of the necessary data, either through interconnection agreements or other binding contracts~~, but it should be clear that compliance obligations can only be imposed on NERC-registered entities listed in the Applicability Section; use of the DP term within proposed Reliability Standard MOD-032-2 should be understood to refer to an entity meeting the NERC registration criteria, unless otherwise specified.

The ~~Standard~~ Drafting Team (~~S~~DT) has concerns that there may be challenges in collecting data for distributed energy resources (DER) connected to unregistered entities. ~~-~~Draft 1 of proposed Reliability Standard MOD-032-2 proposed to assign this data obligation ~~on~~to the Transmission Owner (TO~~/~~) or DP, but based on industry comments, this may place an unreasonable compliance risk on the TO/DP because any unregistered entities that connect DER to their systems have no compliance obligation to provide data to the TO/DP. ~~-~~As such, the ~~S~~DT recommends that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. ~~-~~However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would unnecessarily delay the implementation of DER data requirements. ~~-~~The ~~S~~DT believes there is value in moving forward with MOD-032-2, as it does provide substantial improvement with respect to ensuring ~~-~~DER data is available for inclusion in Planning Coordinator (PC) and Transmission Planner (TP) studies. The DT considered adding "UFLS-Only Distribution Provider" to MOD-032-2 applicability to reduce (but not necessarily eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, adding UFLS-Only Distribution Provider to the applicability would not be appropriate at this time.

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Rationale for Distributed Energy Resource (DER) Definition

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The ~~S~~SDT consensus is that the proposed definition aligns with the intent of the SPIDERWG working definition for DER (which explicitly excludes demand response) and clarifies what is in scope and out of scope with respect to where DER is connected (rather than the technology type~~.~~). Utilizing the existing NERC definition for DP and the associated area of responsibility aligns with the scope of DER data collection and modeling activities and provides clarity for the industry to aid in gathering this information. It should be clear that MOD-032-2 applicability and compliance obligations refer to NERC-registered DPs; the use of the DP term in the DER definition does not in itself imply any compliance obligation.

Below is a summary of the rationale for the ~~S~~SDT departing from each of the seven definitions when proposing a new DER definition.

SPIDERWG definition

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The ~~S~~DT included the language "in non-isolated parallel operation with the Bulk ~~Power~~Electric System" to indicate that ~~distributed energy resources~~DER with potential Bulk Electric System (BES) reliability impacts are those that have electrical connectivity to the BES. The ~~S~~DT intentionally avoided the term "directly connected" to differentiate electrical connectivity from an electrical connection point. ~~-~~Resources that are only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BES and, therefore, are not of interest from a BES-reliability perspective. ~~-~~The ~~S~~DT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry.

IEEE 1547-2018

The ~~S~~DT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the three issues identified above. The ~~S~~DT incorporated the explicit reference to "generation and storage" aspect of the IEEE definition. Further, the IEEE concept of "capable of exporting active power to an EPS" was used to inform the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the ~~S~~DT definition.

At the same time, the ~~S~~DT did not view the IEEE definition as suitable for the ~~S~~DT's intended use as written. The IEEE term qualifies the DER connection point as "not directly connected to a bulk power system" which the ~~S~~DT viewed as potentially ambiguous. Instead, the ~~S~~DT opted for the "connected to the DP's system" language to point to a NERC defined term and concept. ~~-~~The ~~S~~DT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a DER definition for inclusion in the NERC Glossary of Terms.

Federal Energy Regulatory Commission (FERC) Energy Primer

The ~~S~~DT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability planning use cases, the ~~S~~DT and SPIDERWG definitions target sources of electric power, with the ~~S~~DT narrowing this definition to be only sources "capable of providing Real Rower~~.~~." After considering the FERC definition, the ~~S~~DT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)

[1] NERC Glossary of Terms, Updated March 2023. ~~DP is~~Distribution Provider definition is: "Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."

NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the ~~S~~DT concluded it is too broad. After considering the NARUC definition, the ~~S~~DT determined it was not suitable for the intended use.

NERC DERTF

The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the ~~S~~DT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric system" which the ~~S~~DT views as ambiguous and overly broad. After considering the NERC DERTF definition, the ~~S~~DT determined it was not suitable for the intended application.

California Public Utilities Commission (CPUC)

The CPUC definition appears to be based on California legislation and includes energy efficiency, ~~electric vehicles~~EVs, and demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the ~~S~~DT's use. After considering the CPUC definition, the ~~S~~DT determined it was not suitable for the intended application.

New York Independent System Operator (NYISO)

The NYISO definition only considers market-qualifying resources as DER. This definition to exclude a large portion of DER (i.e. retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study. After considering the NYISO definition, the ~~S~~DT determined it was not suitable for the intended application.

Figure 1 below provides a graphic illustration of the DER definition and the intended scope of facilities that would fall under the proposed definition. Figure 2 below shows that the proposed DER and IBR definitions are compatible, but distinct. Some resources may be classified as DER, but not IBR; some resources may be classified as IBR, but not DER; some resources may be classified as both DER and IBR. Note that in Figure 2, "distribution-connected" is shorthand for connected to the DP's system and "bulk system-connected" refers to resources connected to the transmission system.

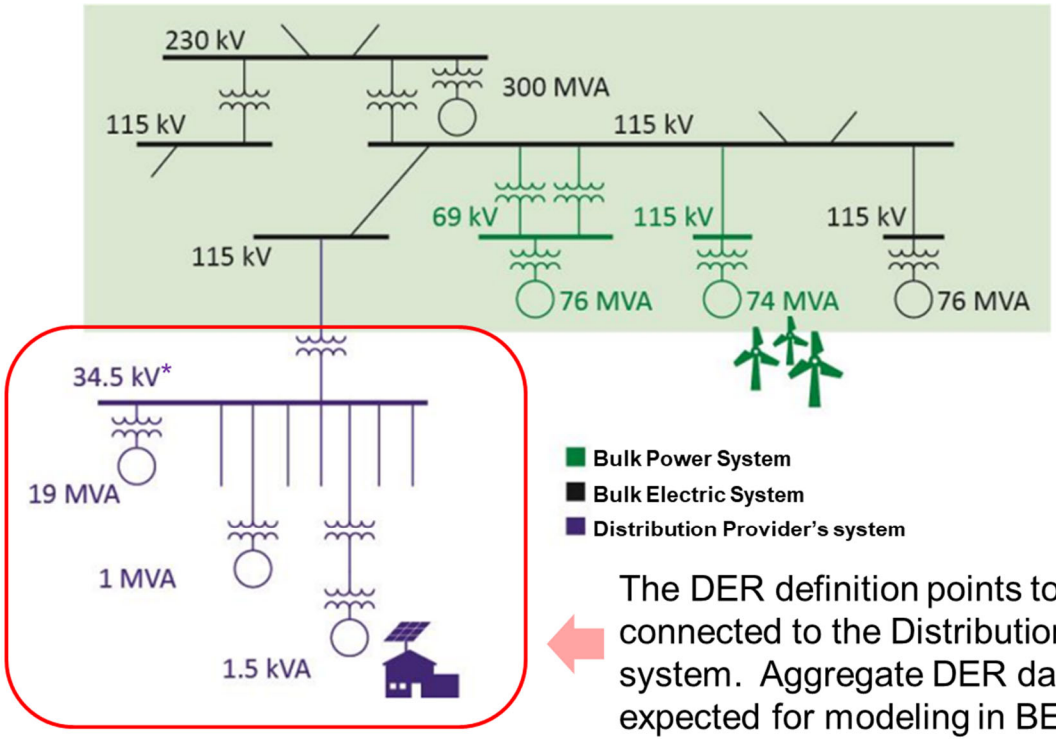


Figure 1: DER Definition Illustration

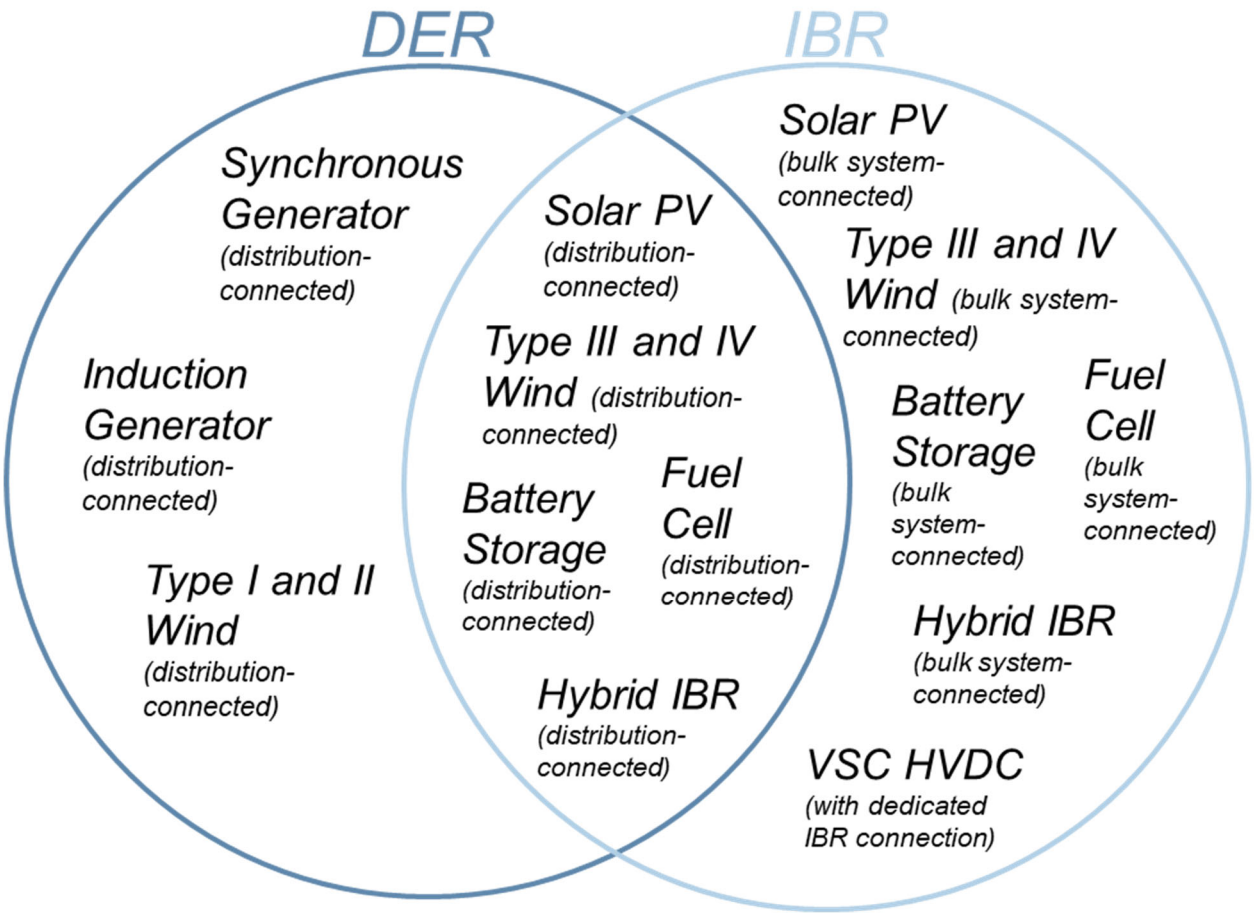


Figure 2: DER and IBR Definition Compatibility

Rationale for Modifications to Attachment 1

MOD-032-2 Attachment 1: Data Reporting Requirements was updated with data specific to DERs. ~~-~~The intent is that all relevant DER data including both utility scale facilities (commonly referred to as U-DER) and smaller behind-the~~-~~-meter facilities (commonly referred to as R-DER) be available and represented in models of the interconnected transmission system consistent with the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. ~~-~~Specific data items listed for DER reflect the minimum amount of information expected to be needed to reasonably represent DER in transmission system models. ~~-~~It is expected that aggregate DER (rather than individual DER facilities) would be represented in most ~~Planning Coordinator/Transmission Planner (~~PC/TP~~)~~ study models. In Draft 3, the word "aggregate" was specifically added to Attachment 1 to clarify this point based on industry comments. However, ~~footnote 4 explicitly allows the PC/TP to specify the level of DER data aggregation. This~~Requirement R1 provides the PC/TP great flexibility ~~for~~in developing data requirements and reporting procedures that align with local practices ~~wherein~~and needs, so long as they include the ~~PC/TP may elect to apply DER aggregation assumptions rather than depend on~~ items listed in the ~~DP/TO to apply aggregation assumptions.~~Requirement R1 Parts.

The PC/TP may have access to sufficient data for modeling certain DER through alternative means (e.g., direct registration of DER in certain markets). ~~-~~In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data, but care will be needed to ensure DER is not double counted. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DER that are excluded from the DP/TO obligation for providing DER modeling data. ~~-~~This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its ~~Planning Coordinator and Transmission Planner~~PC and TP in Requirement R1.

The ~~S~~SDT intentionally maintained flexible language as to whether the underlying DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP/TO applying a combination of approaches to source the data. The PC/TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

The ~~S~~SDT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with the required DER data are only presented in the "steady state" column (though arguably such data is also relevant to "dynamics" and/or "short circuit"). The ~~S~~SDT concluded that this was appropriate and consistent with other "dynamics" line items such as "Wind Turbine Data" and "Photovoltaic systems" that are listed without detailed sub-bullets. ~~-~~Drastically altering the structure of Attachment 1 or explicitly adding DER data to the "short circuit" column was beyond the scope of the Project 2022-02 SAR. ~~-~~However, the PC or TP is not restricted from requiring any needed short circuit data in their joint modeling data requirements and reporting procedures developed per Requirement R1.

It should be noted that the modifications do not make DER a BES facility subject to NERC reliability standards. ~~-~~Instead, the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in ~~i~~Interconnection-wide cases.~~-~~ There are already existing requirements for DPs (or TOs) to provide information about load connected to their systems. ~~-Similar to~~Like load, DER is not generally considered to be a BES facility.~~-~~ However, BES reliability assessments require an accurate representation of both aggregate load and aggregate DER behavior. ~~-~~The modifications proposed in MOD-032-2 are intended to ensure sufficient DER data is available to the PC/TP so that appropriate DER representations can be included in their BES reliability assessments.

- **Inferring DER Capabilities**

As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DER may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. ~~-~~For example, in a certain jurisdiction DER installed after a specified date may be required to have a certain ride-through characteristic. ~~-~~Thus, the appropriate ride-through characteristic representation for DER in that area could be inferred by the in-service date of the DER. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. ~~-~~PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. ~~-~~In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that

the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

- **Inclusion of Data Related to DER Subject to Trip by UFLS and/or UVLS**

There is a reliability need for the DP/TO to convey this information to the PC/TP. ~~-~~As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. ~~-~~Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. ~~-~~In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DER subject to each UVLS/UFLS tripping stage should be identified.

- **Inclusion of Aggregate Demand Clarification**

Footnote 2 was modified to clarify that the gross demand is needed at each load serving bus. ~~-~~Collecting and modeling a net demand that incorporates offsets due to output from DER is not consistent with a modeling framework that explicitly represents DER. ~~In situations where DER is not separately metered, a comparison to historical load levels can be used to approximate the addition of DER on the distribution feeder. A consistent reduction in load on the feeder may be indicative of DER interconnections.~~

- ~~**Examples for** **Footnote** **54**~~

~~Footnote 5 was added to Attachment 1, item 9, after the bracketed statement, indicating the functional entity responsible for data reporting requirements is the "DP, TO where DER is directly connected to the TO system and not through a DP", to cover situations where the DER is not connected to a registered DP or directly to a registered TO. In these situations, DER is connecting to an "unregistered Distribution Provider", that is responsible for DER interconnection processes and data management but does not have NERC compliance obligations. The SDT viewed the collection of all DER data as the appropriate aim, but recognized practical constraints associated with unregistered entity compliance obligations. For that reason, the SDT added a footnote that in part states, "the next closest electrically connected registered entity (DP or TO) shall request DER data and pass through available information" to request data that cannot be required.~~

~~The SDT offers two examples to illustrate the SDT's intended application of Footnote 5:~~

- ~~If the DER is directly connecting to an unregistered Distribution Provider that is immediately electrically adjacent to a registered TO (i.e., "next closest electrically connected registered entity"), the TO is responsible for requesting data from the unregistered DP and incorporating it in the MOD-032 data to the Planning Coordinator.~~
- ~~If the DER is directly connected to an unregistered Distribution Provider that is served by a registered DP (i.e., "next closest electrically connected registered entity"), then the registered DP is required to request data from the unregistered Distribution Provider and include this data in the MOD-032 data submission.~~

Footnote 4 was clarified and Footnote 5 from the previous draft was removed from Attachment 1 to make it clear that the functional entity that is responsible for reporting DER data under the currently available registered entities is the DP. Previous references to the TO as a responsible DER entity were removed, but the clarified footnote still states and recognizes that DER data collection efforts may generally involve DP and TO coordination. The DT continues to recognize that there are situations where DER is connected to an "unregistered Distribution Provider," instead of a DP or TO, and that it is still an appropriate aim to collect this data. However, in agreement with industry comments, references to data collection efforts or passing through data by the DP/TO from these unregistered entities was removed from the standard language as it could add compliance risk on the DP/TO without any compliance obligation on the unregistered entities. The DT believes that there is great value in moving forward with the standard with the registered DP as the responsible entity for DER data as this will vastly improve the amount of data that is available to the TP/PC.

Where an unregistered DP (an entity not meeting the NERC registration criteria) is interconnected to the system of a registered entity (DP or TO), the DP/TO should coordinate with the unregistered DP to ensure the availability of information associated with DER that may be connected to the unregistered DP's system. This effort would be considered as a best practice, even if not specifically required by the MOD-032 Reliability Standard. FERC Order No. 901 addresses this issue of data collection for DERs that do not have an associated registered entity and directs future efforts to determine appropriate responsible registered entities, but the DT believes that this currently falls outside of the scope of this SAR and will be addressed in the new SAR related to FERC Order No. 901, Milestone 3, Part 1. In the interim, FERC Order No. 901 also describes a process where this data is unavailable and should instead be estimated and the limitations of data availability should be documented.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Formal Comment Period Open through October 10, 2024

Now Available

A 45-day formal comment period for **Project 2022-02 Uniform Modeling Framework for IBR** is open through **8 p.m. Eastern, Thursday, October 10, 2024** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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.

This posting affects Phase I of the project for proposed Reliability Standard MOD-032-2 and does not contemplate the SAR related to FERC Order No. 901; the Milestone 3, Part 1.

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 standard and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 1-10, 2024.**

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

For more information or assistance, contact Senior Standards Developer, Laura Anderson (via email) or at 404-782-1870. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project Uniform Modeling Framework for IBR observer list” in the Description Box.



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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 3 - MOD-032-2
Comment Period Start Date:	8/27/2024
Comment Period End Date:	10/10/2024
Associated Ballots:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan AB 3 OT 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 AB 3 ST 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 AB 3 NB

There were 55 sets of responses, including comments from approximately 140 different people from approximately 87 companies representing 7 of the Industry Segments as shown in the table on the following pages.

Questions

1. Given the explanation in the Technical Rationale and responses to industry comments, do you agree with the proposed definition for DER? If you do not agree, please suggest modifications to improve the definition.

2. Do you agree that the modifications for the proposed reliability standard address the scope of the SAR, modifications to MOD-032-1, in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

3. Given the explanation added in the Implementation Plan and in response to industry comments, do you agree with the Implementation Plan for proposed Reliability Standard MOD-032-2?

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
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
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (SRC) 2022-02 Modifications to MOD-032 Draft 3	Ali Miremadi	CAISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					John Pearson	ISO New England, Inc.	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	SPP	2	MRO
					Helen Lainis	IESO	2	NPCC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group, Inc.	3	RF
					Michelle Hribar	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
					Candace Morakinyo	WEC Energy Group, Inc.	4	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,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
					Scott Brame	North Carolina Electric Membership Corporation	1,3,4,5	SERC
					Scott Brame	North Carolina Electric Membership Corporation	1,3,4,5	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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
DTE Energy - Detroit Edison Company	Mohamad Elhusseini	5		DTE Energy	Mohamad Elhusseini	DTE Energy	5	RF
					Patricia Ireland	DTE Energy	4	RF
					Marvin Johnson	DTE Energy - Detroit Edison Company	3	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	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
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Sherri Maxey	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
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. Given the explanation in the Technical Rationale and responses to industry comments, do you agree with the proposed definition for DER? If you do not agree, please suggest modifications to improve the definition.

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

The standard as written places an untenable compliance burden on NERC registered entities. It does not note or address in any way the challenges in collecting DER data from behind the meter facilities connected to DPs or TOs. These unregistered DER owners have no obligation or requirement under NERC standards to provide data for modeling. Requiring that DPs provide modeling data for equipment they do not own and have no means to acquire data on leaves them in a position where they fail to comply with the standard through no fault of their own and despite their best efforts.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

1. The standard does not address responsibilities where legacy DER connected to TP or DP may not have the modeling data to provide.

2. The range of options to expand DP registration criteria mentioned in the technical rationale should be discussed in detail in the standard

3. Constellation recommends that references to “behind the meter” devices be removed. A distributed energy resource’s location relative to the meter does not define it.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No

Document Name	
Comment	
Did the SDT perhaps intend to strike the phrase “not the NERC registered entity” from the bullet which states “Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria not the NERC registered entity?”	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
1. The standard does not address responsibilities where legacy DER connected to TP or DP may not have the modeling data to provide. 2. The range of options to expand DP registration criteria mentioned in the technical rationale should be discussed in detail in the standard 3. Constellation recommends that references to “behind the meter” devices be removed. A distributed energy resource’s location relative to the meter does not define it.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The proposed definition has no boundaries and, as such, would apply to all generators and energy storage systems, no matter the size, e.g. a 1 kW solar panel mounted on a homeowner’s garage. This is unworkable due the sheer number of these that exist. Suggest including boundaries such as those proposed by NERC, i.e. “resources that have an aggregate nameplate capacity of greater than or equal to 20 MVA, delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.” Remove the sub bullet related to the Distribution Provider.	

Adding the reference to Distribution Provider's system but saying it's not referring to the registered DP, which is applicable to this standard, adds unnecessary confusion. Striking the words "connected to the Distribution Provider's system" doesn't affect the definition and removes the confusion. If you are trying to use this to say it includes sub-transmission voltages, just say that; including DP language makes it difficult to figure out the intent.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
NRG supports NAGF's comments and response regarding this question.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports NAGF's comment "The NAGF recommends that references to "behind the meter" devices be removed. A distributed energy resource's location relative to the meter does not define it. The NAGF recommends that the bulleted phrase stating that the term Distribution Provider is referencing NERC Glossary of Terms be removed. It is implicitly understood, unnecessary, and not in line with any other definition. NAGF recommends removal of the phrase "in non-isolated parallel operation." This phrase adds no value and potentially adds unnecessary ambiguity. A potential alternative is to use language similar to that in IEEE 1547 ("not directly connected to the Bulk Power System"). If this phrase is intended to include or exclude any particular type of resource, instead any exclusions or inclusions should be explicitly listed in subparts, as done in the BES definition". Reclamation recommends the DER definition should be added to the Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Andy Thomas On Behalf of: John Sturgeon, Duke Energy , 5, 6, 1, 1; - Andy Thomas	
Answer	No
Document Name	
Comment	

Duke Energy supports implementation of the following NAGF Question 1 responses:

(a) The NAGF recommends that references to “behind the meter” devices be removed. A distributed energy resource’s location relative to the meter does not define it.

(b) The NAGF recommends that the bulleted phrase stating that the term Distribution Provider is referencing NERC Glossary of Terms be removed. It is implicitly understood, unnecessary, and not in line with any other definition.

Duke Energy also supports implementation of EEI Question 1 responses.

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	

Behind the meter generation should not be included.

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 the following concerns from EEI’s comments.

- There is no need to specify that DERs include DERs behind the meter.

- It is not necessary to state that Distribution Provider (DP) are to be understood through the definition provided within the NERC Glossary of Terms. This is true of any term defined in the NERC Glossary of Terms and contained in a NERC Reliability Standard.
- It is preferable to state a DER is designed to export Real Power to the DP's system, rather than "provides Real Power in non-isolated parallel operation with the Bulk Power System".

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 recommends that references to "behind the meter" devices be removed. A distributed energy resource's location relative to the meter does not define it.

The NAGF recommends that the bulleted phrase stating that the term Distribution Provider is referencing NERC Glossary of Terms be removed. It is implicitly understood, unnecessary, and not in line with any other definition.

NAGF recommends removal of the phrase "in non-isolated parallel operation." This phrase adds no value and potentially adds unnecessary ambiguity. A potential alternative is to use language similar to that in IEEE 1547 ("not directly connected to the Bulk Power System"). If this phrase is intended to include or exclude any particular type of resource, instead any exclusions or inclusions should be explicitly listed in subparts, as done in the BES definition.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Oncor Electric Delivery - NA - Not Applicable - Texas RE

Answer	No
Document Name	

Comment

Definition of "Distribution Provider"

As used in the revised draft MOD-32-2, the term "Distribution Provider" ("DP") is ambiguous and should be clarified.

- Earlier comments from industry participants and numerous responses from the drafting team to industry comments on previous drafts clearly show that there is some confusion around the definition of DP as used in this revised MOD-032-2. In one instance, the text points to how "Distribution Provider" is defined in the NERC Glossary of Terms. In another instance, however, the text appears to consider a "Distribution Provider" to meet NERC's registration criteria (as defined in NERC Rules of Procedure, Appendix 5B). To address this persistent confusion, the

drafting team added a note at the beginning of the standard that reads: “Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria.”

- Considering the revised draft MOD-032-2 in isolation, one would reasonably assume that the definition of “Distribution Provider” provided at the beginning of the document to apply to the entire document. The technical rationale included in the document, however, explicitly states this is not the case - the alternative interpretation of “Distribution Provider” is apparently to be used for the rest of the document. This seems needlessly confusing at best and at worst, could cause problems during the implementation of MOD-032-2.

Definition of “Distributed Energy Resource”

- Oncor Electric Delivery Company LLC (“Oncor”) considers the “Distributed Energy Resource” (“DER”) definition used in the Technical Rationale for Reliability Standard MOD-032-2 too vague because it does not contain a voltage class threshold for an energy resource to be considered a DER.
- Oncor’s view of DER is consistent with ERCOT’s definition of DER, which is: “An electrical generating facility consisting of one or more on-site distributed generation units connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system.” This definition can be found here: https://www.ercot.com/files/docs/2017/03/24/DER_OnePager_FINAL.pdf
- From Oncor’s experience, the total capacity of the installation’s on-site distributed generation units may exceed ten megawatts (MW); however, no more than ten MW of the installation’s capacity will be allowed to export into the grid at any point in time at the point of common coupling.
- Is there any MW size threshold for Generator and energy storage technologies to be taken into account when the end-use customer is served at transmission voltage? We would prefer a MW size threshold be specified in the definition.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

TEPC does not agree with the interchangeable use of “Distribution Provider (DP)” between the Applicability/registered entity and the NERC Glossary of Terms definition.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	No
Document Name	

Comment

AZPS supports the comments submitted by EEI on behalf of their members:

While EEI does not object to defining Distributed Energy Resources (DERs), we do question the need. However, if DER needs to be defined, we note the following concerns:

- There is no need to specify that DERs include DERs behind the meter.
- It is not necessary to state that Distribution Provider (DP) are to be understood through the definition provided within the NERC Glossary of Terms. This is true of any term defined in the NERC Glossary of Terms and contained in a NERC Reliability Standard.
- It is preferable to state a DER is designed to export Real Power to the DP's system, rather than "provides Real Power in non-isolated parallel operation with the Bulk Power System".

To address these concerns, we offer the following changes to the proposed DER Definition:

Generators and energy storage technologies connected to a Distribution Provider's system and designed to export Real Power to the Distribution Provider's system.

Likes 0	
Dislikes 0	

Response

Tyler Schwendiman - ReliabilityFirst - 10

Answer	No
Document Name	

Comment

The proposed definition for DER should make it abundantly clear that Invertor Based Resources are included by explicitly including them in the definition. The current definition only includes generators and batteries, but not IBRs such as rooftop solar.

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 EEI.

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	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) does not support the development of an additional NERC Reliability Standard to define DER and believes this DER definition is too prescriptive. CEHE recommends that data reporting requirements for DERs listed in Attachment 1 be determined by the Planning Coordinator, in coordination with the Transmission Planner.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
The definition of distributed energy resources lacks sufficient specificity by not including solar resources. Even though the definition of distributed energy includes “energy storage technologies”, it might not be sufficient to imply it includes solar resources. MRO recommends, for example, using “energy resources and energy storage technologies connected to…..” in the definition to ensure it includes all types of energy resources.	
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	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While EEI does not object to defining Distributed Energy Resources (DERs), we do question the need. However, if DER needs to be defined, we note the following concerns:

- There is no need to specify that DERs include DERs behind the meter.
- It is not necessary to state that Distribution Provider (DP) are to be understood through the definition provided within the NERC Glossary of Terms. This is true of any term defined in the NERC Glossary of Terms and contained in a NERC Reliability Standard.
- It is preferable to state a DER is designed to export Real Power to the DP's system, rather than "provides Real Power in non-isolated parallel operation with the Bulk Power System".

To address these concerns, we offer the following changes to the proposed **DER Definition** (in bold face):

Generators and energy storage technologies connected to **a** Distribution Provider's system **and designed to export Real Power to the Distribution Provider's system.**

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	

Comment

WECC suggests the Drafting Team use “end-use” in the definition for consistency with Glossary of Terms (i.e., hyphenate the term). Is there any concern that the Distribution Provider’s system, by definition, stops at the end-use customer but the DER definition goes beyond that interface (or appears to)? While the Technical Rationale provides a good description of the inter-relatedness of IBR and DER definitions but the DER definition itself is not clear.

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 supports the following comments provided by the North American Generator Forum (NAGF) to improve the definition:

(1) The NAGF recommends that references to “behind the meter” devices be removed. A distributed energy resource’s location relative to the meter does not define it.

(2) The NAGF recommends that the bulleted phrase stating that the term Distribution Provider is referencing NERC Glossary of Terms be removed. It is implicitly understood, unnecessary, and not in line with any other definition.

In addition, the DER definition needs some threshold limits for what DER data must be reported so that entities are solely focused on the aggregate DERs of significant size that may impact the Bulk Power System. The registration criteria for Category 2 Generator Owners and Generator Operators uses an aggregate capacity of 20 MVA or more, connected to a common point of connection at 60 kV and above. This criteria is comparable to other generation resources applicable to NERC reliability standards and would eliminate the need for Distribution Providers to consider every residential solar PV installation.

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	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	MRO NSRF MOD-032 Comments Project 2022-02 NSRF 10-9-2024.docx
Comment	
Please view comments in the attachment.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNM and TNMP support the establishment of an aggregate MVA threshold that would determine applicability to Distribution Provider. Also, PNM supports the DER definition development in a separate NERC Reliability Standards project.	
Likes 0	
Dislikes 0	

Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	No
Document Name	
Comment	
Hydro One recommendation is to add a note for rotating loads. ***Rotating loads such as large induction or synchronous motors, which have the ability to backfeed momentarily during a disturbance, are specifically excluded.***	
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 the opinion of ACES that the currently proposed definition of DER is inherently flawed and rife with ambiguity.

Firstly, we take great issue with the phrase “Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria.” We believe that the term Distribution Provider (DP) is a well-defined term in widespread use throughout the industry and is universally understood to refer to a NERC registered entity. Using this term in such a unique manner as is done in the proposed DER definition will only create confusion and cause consternation for registered entities. This is further compounded by the stark contrast between the currently proposed draft 3 of MOD-032-2 and the updated Technical Rationale. The 1st paragraph on page 1 of the Technical Rationale states (emphasis added):

“It is recognized that some distribution facilities do not have an associated DP that meets the NERC registration criteria, but it should be clear that compliance obligations can only be imposed on NERC-registered entities listed in the Applicability Section; use of the DP term within proposed Reliability Standard MOD-032-2 should be understood to refer to an entity meeting the NERC registration criteria, unless otherwise specified.”

It is our understanding that the intent of the Technical Rationale is to support and provide additional clarification and context for the enumerated requirements within a given Reliability Standard. If the Technical Rationale blatantly contradicts rather than bolsters the Reliability Standard that is intended to support, then in our opinion, the Technical Rationale fails to fulfill its intended purpose.

Moreover, the term DP is used throughout the NERC Rules of Procedure for describing an entity that meets NERC registration criteria.

Page 1 of Appendix 2 to the Rules of Procedure states:

“For purposes of the NERC Rules of Procedure, including all Appendices, the terms defined in this Appendix shall have the meanings set forth herein.”

Page 2 of Appendix 2 states:

““Distribution Provider” means the entity that provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.**”

As evidenced above, the NERC Rules of Procedure clearly uses the same definition to refer to a DP as is used in the Glossary of Terms. In fact, this explicitly stated within Appendix 2.

Page 1 of Appendix 2 states:

“Definitions of terms in this Appendix that are marked with asterisks (**) are taken from the NERC Glossary of Terms Used in Reliability Standards.”

Furthermore, page 1 of Appendix 5A to the NERC Rules of Procedure contains a chart identifying entities that must register. Please see the screenshot included as an attachment for reference (emphasis added):

Secondly, ACES and its Members have additional concerns with the proposed DER definition surrounding the phrase “including those connected behind the meter of an end use customer”. It is the opinion of ACES that by including the aforementioned phrase, the DT has created a situation wherein both Registered Entities and unregistered entities will now have compliance obligations under the purview of MOD-032-1. If our interpretation is correct then, in our opinion, this represents a gross overreach of NERC’s statutory authority. We believe this concern is best expressed in the 2nd paragraph on page 1 of the Technical Rationale which states (emphasis added):

“The Drafting Team (DT) has concerns that there may be challenges in collecting data for distributed energy resources (DER) connected to unregistered entities.”

Conversely, if the intent of this phrase is to require the NERC Registered Entity to collect data from non-registered entities, then doing so creates an insurmountable compliance burden and immeasurably increases the compliance risk for said NERC Registered Entity. In short, by what mechanism is the NERC Registered Entity able to require unregistered entities to provide data?

Additionally, what recourse does the NERC Registered Entity have if the unregistered entity is either unable or unwilling to provide said data at all or is unable or unwilling to do so in a timely manner to meet compliance deadlines? It is apparent that the DT shares our concerns as these very issues are enumerated within paragraph 2 on page 1 of the Technical Rationale which states:

“…this may place an unreasonable compliance risk on the TO/DP because any unregistered entities that connect DER to their systems have no compliance obligation to provide data to the TO/DP. As such, the DT recommends that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap.”

Thus, we recommend modifying the DER definition as follows:

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider’s system that are capable of providing Real Power and/or Reactive Power in non-isolated parallel operation with the Bulk-Power System.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
SRP supports the comments provided by the North American Generator Forum (NAGF) to improve the definition.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Providing the DP/TO/TP the authority to determine the appropriate levels of DER that would be impactful, or material, would ensure the needed flexibility and agility for systems with either large or small populations where one size does not fit all. • It is preferable to state a DER is designed to export Real Power to the DP's system, rather than "provides Real Power in non-isolated parallel operation with the Bulk Power System". Many DER installations are designed to provide power to a specific end-user with the ability to provide any excess power to the DP system. • The models provided to the PC/TP may be either specific to a DER unit (for larger installations) or utilize the NERC generic DER model, when small DER units are aggregated.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
We recommend that a separate definition for Aggregate DER be developed. A distinction between individual units with compliance requirements and the representation of multiple units into an aggregate with differing compliance requirements will add clarity to what is expected in MOD-032 and TPL-001.	
Likes 0	
Dislikes 0	
Response	

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

Concepts needed to improve the standard:

Providing the DP with the authority to determine what DERs are impactful will ensure flexibility and agility for large population standards where one size does not fit all.

Example Footnote 4 Revisions: For purposes of this item, the Distribution Provider to which **aggregated** DERs **is are** connected **is shall be for reporting responsible for providing aggregated DER composite model[s] using its sole engineering judgement based on criteria determined by the DP in conjunction with the TO/TP that contains generalized characteristics of the type of DERs identified by DER type under 9c DERs data, generally through coordination with to** the Transmission Owner**,**. **in accordance with PC/TP modeling data requirements and data reporting procedures developed under Requirement R1. The PC or TP may need to coordinate with the DP or TO to determine appropriate equivalent distribution system impedance.**

Clarify behind the meter DERs aren't may not necessary (and may not be feasible to monitor) unless in continuous parallel and designed to export power to the BPS.

Consider replacing "non-isolated parallel" with "continuous parallel" that can export real power to the BPS.

Consider modifying the DER definition with:

Generators and energy storage technologies connected to **the a** Distribution Provider's system **and designed to export Real Power in continuous parallel to the BPS.**

, including those connected behind the meter of an end use customer, that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System.

Distribution Provider refers to the NERC glossary definition, rather than an entity meeting the NERC registration criteria.

Clarify unregistered entities are not included in MOD-032 DERs.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E is not providing any input for Question 1.	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the North American Generator Forum (NAGF) on question 1	

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) 2022-02 Modifications to MOD-032 Draft 3	
Answer	Yes
Document Name	
Comment	
The **ISO/RTO Council Standards Review Committee (SRC)**[1] supports the Distributed Energy Resource (DER) definition proposed by the drafting team, understanding that the intent is to keep the definition generic, like many other definitions in the NERC Glossary of Terms (e.g., Distribution Provider, Disturbance Monitoring Equipment, Load, etc.). [1] For purposes of these comments, the SRC includes the following entities: CAISO, ERCOT, IESO, ISO-NE, MISO, NYISO, PJM and SPP.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own. In addition, ERCOT notes that the proposed DER definition uses the term "Bulk-Power System," while the discussion of that portion of the definition on page 3 of the Technical Rationale uses the term "Bulk Electric System." ERCOT recommends that the Technical Rationale be revised to match the proposed DER definition.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	

Comment	
PJM supports the IRC SRC comments.	
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; John Nierenberg, 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	
Tacoma Power agrees with the proposed DER definition. However, in order to apply this definition in the context of the MOD-032 Standard, Tacoma Power recommends a phased-in implementation based on DER modeling thresholds (see comment for 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	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 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	
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	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
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	

2. Do you agree that the modifications for the proposed reliability standard address the scope of the SAR, modifications to MOD-032-1, in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

The potential size of the TO and DP data collection processes and methods could be immense and costly. Without clear boundaries DERs are potentially unbounded and could reach well into the distribution. NERC has suggested that data collection for residential rooftop systems down to 1.5 kVA are potentially within scope. Mandating data collection of such systems transfers the compliance burden to the DP versus NERC which is costly and inappropriate.

Providing the DP, in conjunction the TO/TP, have the latitude to set the criteria as necessary to ensure impactful DERs are properly captured.

Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	

The expansion of the generation data collection requirements to include small-scale generation adds a burden to the utilities and is in conflict with the Michigan State policy. The current interconnection process for generation connected to the distribution system is well-established, and the collection of UFLS/ULVS load-shedding and dynamic data from these generators will require a significant change for future interconnections – information that is generally not available to homeowners from their installers. For those who already have connection agreements, some dating back over 50 years, there is no means to re-collect this data. This solution is not likely to be cost effective given the uncertainty around the tools and information gathering necessary to collect the data on legacy generators in order to maintain compliance, and whether compliance is truly possible even with heavy investment. The standard would be better written to define parameters around the size of the unit, its connection, and its anticipated substantial impact on the BES as to whether such data collection is necessary.

If the aggregating of generation data to a single unit within the model data is acceptable, then that should be explicitly stated in a footnote along with what NERC accepted dynamic models may be used. In order to implement the DER definition within the scope of the implementation plan, Distribution Providers absolutely must have clarity on the technical scope of what modeling data will be required prior to implementation. If left to the Balancing Authority/TPs/etc. to discuss and determine the acceptable scope of model data and software requirements, data collection for the Distribution Providers and others responsible for compiling this data will not be left with enough time to meet the standard requirements.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Some DER entities connected to the DP system over 30 years ago and are still operating today. The data for these units may not be readily available and could be very costly to obtain. Additionally, even with good intentions, some DER may be missed when trying to identify and aggregate all DER. Since no provision has been provided to not be held liable if either of these is true, an allowance should be provided if the DP made a good faith effort to obtain all of the records.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
SRP supports comments provided by North American Generator Forum (NAGF) that “Many of the technologies needed to provide the data referenced in the draft standard are not currently available and/or installed”.	
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; John Nierenberg, 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	
The MOD-032 Standard should include the language from the Technical Rationale recognizing that there are situations where this data is unavailable and should instead be estimated and the limitations of data availability should be documented. In order to emphasize that a PC does not need to perform unreasonable effort to obtain data that is unavailable, Tacoma Power recommends adding this sentence from the Technical Rationale into the	

Measure for R4: “If this data is unavailable, then Planning Coordinator will work with DP and be able to use either estimated or default data and should provide evidence documenting the limitations of the data availability and the justification for the estimations used in the model”.

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 have an ongoing concern regarding the burden this will place upon the DP by requiring DPs to collect data for any DER connected to the DP’s system. The proposed draft establishes a zero MVA threshold for the collection of DER data for all resources "in non-isolated parallel operation with the Bulk Power System”. Per the Technical Rationale, this includes every residential solar and commercial rooftop solar customer on the DP’s systems.

Furthermore, as written, the proposed MOD-032-1 standard would include every electric vehicle (EV) that is capable of providing power to the BPS. Is the DP now expected to collect information from residential customers whenever said customer buys an EV? This is further compounded by the fact that every manufacturer of EVs has the freedom and flexibility to design their vehicles to meet their own independent specifications. Please consider the following hypothetical scenario:

An end-use residential customer buys a Tesla and has it connected to the grid. In an effort to reduce their electric bill, the customer connects their EV and enables it to discharge the battery during periods of high electrical demand. The end-use residential customer then decides to upgrade their vehicle and now buys a Ford F-150 Lightening. The F-150 potentially has a vastly different power output and battery discharge curve from the Tesla the customer previously owned. How is the DP expected to be able to provide accurate modeling data in such a scenario? Is the DP expected to require the end-use customer to get approval prior to buying a new vehicle?

In short, the lack of an MVA threshold for these resources goes beyond **any** previous precedent for a NERC Reliability Standard and places an unreasonable compliance burden on the DP.

Additionally, we are concerned that attempting to collect DER data at such a low level will place a huge strain on the already limited resources of our Members. This is especially compounded by the fact that, at present, DERs owned by end-use residential customers have not been clearly demonstrated to have a material impact on the reliability of the BPS.

In summary, we fear that by not establishing a non-zero MVA threshold, the currently proposed draft of MOD-032-2 may exhaust all available resources to the point that some entities may be forced to choose between compliance with this Reliability Standard or providing reliable electricity to end-use customers.

Therefore, ACES recommends modifying Section 4 Applicability as follows:

4. Applicability:

4.1. Functional Entities:

4.1.1. Balancing Authority

4.1.2. Distribution Provider

4.1.3. Generator Owner

4.1.4. Planning Authority/Planning Coordinator (hereafter referred to as “Planning Coordinator”)

4.1.5. Resource Planner

4.1.6. Transmission Owner

4.1.7. Transmission Planner

4.1.8. Transmission Service Provider

4.2. Facilities

4.2.1. Bulk Electric System (BES) Facilities; and

4.2.2. Non-BES Distributed Energy Resources connected at a voltage of 20 kV or above with:

4.2.2.1. Gross individual nameplate rating greater than 10 MVA. Or,

4.2.2.2. Gross facility aggregate nameplate rating greater than 10 MVA.

Likes 0	
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	No
Document Name	

Comment

Cost impacts are not fully known. No assessment could be made at this moment where there is no clear identification on the exact criteria for data collection.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment
PNM & TNMP requests the MVA threshold establishment for a DER prior to assessing the cost effectiveness of implementation.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment
The potential size of the TO and DP data collection processes and methods could be immense and costly. Without clear boundaries DERs are potentially unbounded and could reach well into the distribution. NERC has suggested that data collection for residential rooftop systems down to 1.5 kVA are potentially within scope. Mandating data collection of such systems transfers the compliance burden to the DP versus NERC which is costly and inappropriate. Providing the DP, in conjunction the TO/TP, have the latitude to set the criteria as necessary to ensure impactful DERs are properly captured.

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 supports the comments provided by Tacoma Power.

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	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not support the changes made to MOD-032-1 because we believe that the cost to gather and report the level of data being proposed will far exceed the reliability benefit that will be provided through these modeling enhancements. Also, the addition of behind the meter generation to the DER Definition will add cost and burden on us due to the scope of data that is required to be collected from individual households within the DPs footprint.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Per question 1 above, would like more clarity for the DER proposed definition and separation of the DP Functional Entity and DP glossary term. Could result in additional testing and modeling burden for DER elements. Add further burden to PC/TP's identifying registered DP's and gathering modeling data as laid out in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	

Answer	No
Document Name	

Comment

AES Clean Energy agrees with and supports MRO NSRF comments that the DER definition should have thresholds that havebased on material impact to the reliability of the BPS. The aggregate 20 MVA of real power generation and aggregated to a Point of Interconnection of 60 kV and greater should be used for DER to align with the newly introduced Category 2 definition by NERC.. DER definitions without bounds could result in unintended consequences.

{C} {C}{C}These unintended consequences will include size and cost of data collection process and methods which cannot be cannot be fully comprehended without clear boundaries and thresholds for the DER definition. DPs that are required to submit this datamodeling data for DER resources could potentially have to spend a lot of time and resources in gathering the data from the DER owners.

Likes 0	
Dislikes 0	

Response

Broc Bruton - Oncor Electric Delivery - NA - Not Applicable - Texas RE

Answer	No
Document Name	

Comment

A large point of concern in previous draft comments has been related to the draft MOD-032-2's inappropriately placing reporting obligations and compliance responsibility on the Transmission Owner ("TO"). In the original draft of MOD-032-2, the standard was explicit that DER data is the responsibility of the TO when a DER is not associated with a NERC registered DP. Because unregistered entities have no obligation to provide this data to the TO, the current draft MOD-032-2 is essentially setting the TO up for non-compliance because the TO will have no ability to force the unregistered entities to provide the needed data.

- In the current draft, the drafting team has acknowledged this issue and clarified in its comments, the technical justification, and the standard to try to alleviate industry concerns.
- While the current draft of MOD-032-2 now explicitly states that the responsibility for reporting DER data is with the DP connected to the DER, there is also a note that this reporting will be accomplished "generally through coordination with the Transmission Owner."
    - Oncor's concern is whether a "failure of coordination" between the DP and TO could result in a shared violation of data reporting requirements?
    - If the answer is "yes," then Oncor has the following question: What constitutes a "failure of coordination"?
        - This concern further reinforces the need to clarify the definition of DP used throughout the standard, as it stands to reason that a "failure of coordination" is more likely with an unregistered DP that is not compelled to coordinate to supply DER data.
    - If the answer is "no," then the phrase "generally through coordination with the Transmission Owner" should be removed to alleviate this concern. The updated phrasing is still accurate but more concise: "For purposes of this item, the Distribution Provider to which DER is connected is responsible for reporting DER data in accordance with PC/TP modeling data requirements and data reporting procedures developed under Requirement R1."

Likes 0	
Dislikes 0	

Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Many of the technologies needed to provide the data referenced in this draft standard are not currently available and/or installed.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Cost-effectiveness can not be determined.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Andy Thomas On Behalf of: John Sturgeon, Duke Energy , 5, 6, 1, 1; - Andy Thomas	
Answer	No
Document Name	
Comment	
Duke Energy supports implementation of EEI Question 2 responses.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports NAGF's comment "Many of the technologies needed to provide the data referenced in the draft standard are not currently available and/or installed".	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Many of the technologies needed to provide the data referenced in the is draft standard are not currently available and/or installed.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	
PG&E does not have any comments on the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	

Answer	No
Document Name	
Comment	
There are legacy DER that cannot meet the standard and should have exclusion criteria. Further, without a DER size identified, cost-effectiveness cannot be determined. As stated in the response(s) to the first round of comments, the DT is not providing a size in the proposed DER definition and that is left up to the PC/TP to determine.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
No, if the TP and/or PC require the additional data such as Harmonics, Protection Element Status, or Inverter Fault Codes to also be recorded and included in the validation of models, this could require the installation of costly data recording equipment such as DFRs or additional metering.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
There are legacy DER that cannot meet the standard and should have exclusion criteria. Further, without a DER size identified, cost-effectiveness cannot be determined. As stated in the response(s) to the first round of comments, the DT is not providing a size in the proposed DER definition and that is left up to the PC/TP to determine. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
As written, we feel unclear on the Dynamic Aggregate Distributed Energy Resource date criteria #10. FirstEnergy suggest that the word “including” be replaced with “limited to” - to clarify definition of Dynamic Aggregation DER data requested. Criteria #10 would read: Aggregate Distributed Energy Resource (DER) data **limited to** whether DER is subject to tripping in conjunction with UFLS and/or UVLS4.	
Likes 0	
Dislikes 0	
Response	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	No
Document Name	
Comment	
SMECO agrees with ACES comments: We are not clear on what the SDT is trying to say in the following: From Section 4 of Attachment 2: Section 3.1.4: documentation showing the ability to protect user authentication information for user-initiated electronic access applicable to Section 3.1.3 while in transit between the Cyber System outside the asset containing low impact BCS or SCI that supports a low impact BCS and • The asset containing low impact BCS or SCI that supports a low impact BCS, It seems that the bullet is an exact duplicate of the body of the explanation above the bullet? Is the SDT trying to cover communications between two (2) different LIBCS with this statement?	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	

Answer	No
Document Name	
Comment	
The addition of behind the meter generation to the DER Definition prevents this standard from being complied with in a cost-effective manner due to the scope of data that is required to be collected from individual households within the DPs footprint. Removing behind the meter generation from DER definition would reduce the scope of work required to comply with standard to something that is more cost effective.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
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 2	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
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	
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	
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	
Ronald Hoover - 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	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	
Document Name	
Comment	
Ameren will not comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No comment on the cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	

N/A for MRO	
Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
RF does not comment on this.	
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	
Isidoro Behar - Long Island Power Authority - 1	
Answer	
Document Name	
Comment	
[Response is neither Yes nor No]	

It is recognized that Requirement R1 and the revised Attachment 1 are intended to provide the PC/TP flexibility in developing data requirements and reporting procedures that align with local practices and needs, so long as they include the items listed in the Requirement R1 Parts. However, the cost effectiveness of the proposed standard modifications cannot be determined until the steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the new DER requirements are actually developed. It is anticipated that significant changes to certain load forecasting practices will be required, as well as development of new/expanded processes to be able to forecast DER and translate DER data into power flow, dynamics and short circuit models. There may be significant costs / uplift borne by PCs, TPs and TOs/DPs to accomplish all of this.

Likes 0	
Dislikes 0	

Response

3. Given the explanation added in the Implementation Plan and in response to industry comments, do you agree with the Implementation Plan for proposed Reliability Standard MOD-032-2?

Srikanth Chennupati - Entergy - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Due to the scope of work created by the requirement to include behind the meter generation in the data submittal it would not be possible for many DPs to complete this work in12 months as required for R2, R3, R4.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

See our comment above.

See our comment in response to Q2. Due to unclear expectations from this draft, FirstEnergy cannot support the implementation plan.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation aligns with NAGF comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
No, we do not feel that it is ample time to be able to comply with MOD-032-2 within 12 months of the approval of the Standard due to the TP and PC may not have the new data requirements indentified by the effective date of the Standard, therefore DPs may not have ample time to gather all the data for the DERs that are connected to their systems.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP is unable to support the proposed Implementation Plan due to our concerns regarding the obligations themselves, and the challenges associated by obtaining data from entities with no obligations to provide it.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Constellation aligns with the NAGF comments.	

Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The added text (indented below) under the section titled “General Considerations” is unenforceable.

Transmission Owners (TOs)s and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods more than 12 months prior to the effective dates of Requirements R2, R3, and R4. In summary, this would give a full 36 months from FERC approval until data is required to be reported.

In reference to the first part of the first sentence - while the TOs and DPs COULD participate in the PC/TP process, they cannot be “expected to” as there is no requirement for them to do so until the standard is enforceable. Similarly, in the second part of the first sentence, they COULD be able to start working on data collection, but they are not required to do so. As such, the 36-month timeframe referred to in the second sentence is not truly correct and gives the perception of more time for implementation than is real.

As such, the implementation timeframe of 12 months after the effective date is too short and should be extended to at least 24 calendar months.

Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

Due to many of the technologies necessary to provide the data required by this standard, are either not currently installed or even available, NRG does not support the implementation plan

Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports NAGF’s comment “Due to many of the technologies necessary to provide the data required by this standard either not currently installed or even available", Reclamation does not support the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Andy Thomas On Behalf of: John Sturgeon, Duke Energy , 5, 6, 1, 1; - Andy Thomas	
Answer	No
Document Name	
Comment	
Duke Energy supports implementation of EEI Question 3 responses.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Given the complexity, the implementation plan should be extended to five years.	
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 EEI's concerns that the expectations contained in MOD-032-2 (Attachment 1) regarding what DPs can provide go beyond what is currently possible for most DPs.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Due to many of the technologies necessary to provide the data required by this standard, are either not currently installed or even available, NAGF does not support the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
AZPS supports the comments submitted by EEI on behalf of their members: While EEI does not object to the proposed implementation plan as proposed, we are concerned that the expectations contained in MOD-032-2 (Attachment 1) regarding what DPs can provide go beyond what is currently possible for most DPs. (See our comments to Question 4, which describe what DPs are capable of providing to planners.)	
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 EEI.	
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	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not support the proposed changes to MOD-032-2 and therefore cannot support the Implementation Plan. CEHE supports Edison Electric Institute's (EEI) comments on the expectations contained in MOD-032-2 specifically, the language in Attachment 1 (Item 9) does not align with what DPs can provide regarding the DER resources connected to their system.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No

Document Name	
Comment	
While EEI does not object to the proposed implementation plan as proposed, we are concerned that the expectations contained in MOD-032-2 (Attachment 1) regarding what DPs can provide go beyond what is currently possible for most DPs. (See our comments to Question 4, which describe what DPs are capable of providing to planners.)	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	
WECC believes the Implementation Plan is too long for an issue that has been actively discussed for several years.	
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	
If no threshold limits are applied to the DERs for which data must be provided, then SMUD does not agree with the implementation plan because more time will be needed to allow entities to expand their modeling capabilities and to determine how to collect this data.	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF), and the North American Generator Forum (NAGF) on question 3	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The MRO NSRF remains concerned the expectations contained in MOD-032-2 (Attachment 1) regarding what Distribution Providers (DPs) can provide goes beyond what is currently possible for most DPs. Specifically, the language in Attachment 1 (Item 9) does not align with what DPs can provide regarding the DER resources connected to their system. In most cases, DPs do not monitor those resources in real-time and most would need to deploy extensive upgrades to their system before they could provide the detailed information, even in aggregate, for DER performance (i.e., ride-through, voltage control and frequency control). While this will be possible in the future once Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS) are more broadly deployed, such details may be impossible to provide for most DPs at this time.	
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	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNM & TNMP requests the MVA threshold establishment for a DER prior to assessing the cost effectiveness of implementation. PNM also supports EEI's comments regarding Distribution Provider monitoring capabilities listed in Attachement 9, criteria "d.".	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
SRP supports comments from MRO NSRF that the DER definition should have thresholds that have based on material impact to the reliability of the BPS.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The proposed implementation plan may not be sufficient for the DP to provide all of the items identified in Attachment 1. Additionally, the information required in Attachment 1 Item 9d may not be available to the DPs based on the DPs/States requirements for data from DER entities to connect to the DP system. This item should include either a footnote or provision of - if available.	

Additionally, the requirement for DPs to determine and provide the appropriate equivalent distribution system impedance should be removed from Footnote 4. The method for locating the DER data should be left to the TO/DP so that the addition of DER data does not cause solution issues for the model.	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy remains concerned the expectations contained in MOD-032-2 (Attachment 1) regarding what Distribution Providers (DPs) can provide goes beyond what is currently possible for most DPs. Specifically, the language in Attachment 1 (Item 9) does not align with what DPs can provide regarding the DER resources connected to their system. In most cases, DPs do not monitor those resources in real-time and most would need to deploy extensive upgrades to their system before they could provide the detailed information, even in aggregate, for DER performance (i.e., ride-through, voltage control and frequency control). While this will be possible in the future once Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS) are more broadly deployed, such details may be impossible to provide for most DPs at this time.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E is not providing any input for Question 3.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	
Comment	
PJM supports the IRC SRC comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) 2022-02 Modifications to MOD-032 Draft 3	
Answer	Yes
Document Name	
Comment	
The SRC believes the 36-month proposed implementation period should be sufficient.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Broc Bruton - Oncor Electric Delivery - NA - Not Applicable - Texas RE	
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	
Tyler Schwendiman - ReliabilityFirst - 10	
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	
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	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
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	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
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	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
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	
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; John Nierenberg, 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 concurs with the Implementation Plan change to allow 24-months for implementation of MOD-032-2. However, Tacoma Power is concerned that 24-months will not be sufficient to collect the data necessary for all DER resources. Specifically, with the change in the DER definition to include behind-the-meter data and the additional clarification from the SDT that the threshold for data collection is zero (essentially all DER), Tacoma Power recommends that additional time is needed for entities to determine how to collect this data. As other commenters have noted, data will need to be collected from entities which may or may not have the monitoring capabilities installed in their systems to capture this data. Coordination with these entities to determine responsibility for the monitoring equipment and then purchasing/installation of this equipment will take longer than 24 months.

To address this concern, Tacoma Power recommends developing a phased-in implementation plan based on modeling thresholds. For example, within 24-months of the effective date of the Standard, provide DER data for aggregate 1 MW generation, and then a 36 month phased-in implementation plan for no threshold / all DER data. This longer phased-in implementation for all DER data would allow entities to sufficiently revise procedures for coordination with other entities while also expanding the modeling and monitoring capabilities.

Proposed revisions to Implementation Plan:

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised PC/TP data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 based on the following thresholds:

- until 12 months after the effective date of Reliability Standard MOD-032-2 for aggregate DERs at bus greater than or equal to 1 MW real power generation,
- until 36 months after the effective date of Reliability Standard MOD-032-2 for the remaining DERs connected to the BPS, regardless of real power generation.

Likes 0	
Dislikes 0	

Response

4. Provide any additional comments for the standard drafting team to consider, if desired.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	
Document Name	
Comment	
Ameren would like more clarification around the classification of Category 2 generators. It is not in the Venn diagram in the Technical Rationale. We do not support the changes, the responsibility should be on someone besides the utility.	
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	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
Proposed New Footnote 5 to address the limitation TOs and DPs often have regarding detailed data for IBR and DER resources they do not own or have the regulatory authority to collect (for Item 10 Steady State column and Item 11 Dynamics column and Item 3 Short Circuit column) For purposes of this item, the TP/PCs are limited in the information that they can request from TOs and DPs for DER modeling purposes to information that TOs and DPs obtain through their interconnection process.	
Likes 0	

Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
Document Name	
Comment	
SRP supports the additional comments from MRO NSRF.	
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; John Nierenberg, 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 adequate modeling of DER. However, we are concerned the current proposal could actually result in less detailed transient study. Detailed dynamic models such as the composite load model for aggregate load are only used when the aggregate load exceeds 1-5 MW. Below this threshold, a static rather than a dynamic model is used.

Typically the level of aggregation for load and distribution generation is different than the point at which UFLS relays are placed on the actual power grid. For example, inside the WECC base case load/gen is typically listed at the high voltage side of a substation transformer. The substation transformer and distribution circuits are included by turning on composite load model. However, UFLS relays are often physically placed on individual distribution circuits and modeled as tripping a certain percentage of overall substation load. Under the proposed revisions, the highest level of load/gen aggregation that could occur would be at the location where the UFLS relay is physically installed. At a typical substation this could result in numerous loads that are too small to use the composite load model.

An additional concern with numerical simulations is many load buses in the WECC system are likely to have at least 6 different DER characteristics (e.g. IEEE-1547 2003, IEEE 1547a-2014, IEEE 1547-2018, IEEE 1547-2018 with Utility specific settings, distributed Hydro, other). Even when the aggregate DER at a bus exceeds 1.0 MW, many of the categories will have much less than 1 MW of each DER characteristic. For many of Tacoma Power's substation load models, there will be a single residential customer with less than 0.010 MW of solar generation with pre-2014 vintage inverters. We question whether attempting to include such small values into a transient simulation will actually provide a more realistic result.

Additionally, we should consider how this requirement may influence where utilities choose to place UFLS relays. In general, placing UFLS relays on distribution circuits rather than substation or transmission lines provides greater flexibility for avoiding undesired tripping of distributed generation or of equipment serving critical natural gas infrastructure. Rather than focusing on including both UFLS and DER into the MOD-032 data template, Tacoma

Power would prefer modifications to PRC-006 directing UFLS entities to consider the impacts of DER on UFLS locations. This would be similar to the requirement in EOP-011-4 to manage overlap between operator controlled load shedding and automatic load shedding.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	
Document Name	
Comment	
· At the moment, it is not entirely clear what performance related requirements are intended to be addressed under the “Dynamics” column for Aggregated DER resources. If all that is sought is what is specifically listed (i.e. whether DER is subject to tripping in conjunction with UFLS and/or UVLS), then we can accept. However the inclusion of the word “including” in the preceding phrase leaves the requirement wide open to interpretation, potentially seeking more details that could pose undue challenges to manage. It would be helpful to clarify this further, in particular to identify what performance measures or operational needs the “Dynamics” data is intended to address. · In addition to the above, consideration may be appropriate for exclusions, allowing grandfathering of existing projects and establishing capacity thresholds for DERs to exempt less impactful smaller projects (e.g. exempt < 100 kW?).	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	

Answer	
Document Name	
Comment	
SPP recommends that bullet 9D language (in the Steady state section of Attachment 1) be added to the Dynamic section as well. We feel that this is applicable to Ride-through events, and this is the appropriate section to put the language in since it's associated with transient state characteristics.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNM & TNMP requests the MVA threshold establishment for a DER prior to assessing the cost effectiveness of implementation. With an established threshold determined, Distribution Provider could be capable of monitoring parameters listed in Attachment 9 related to ridethrough, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.	
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	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (SRC) 2022-02 Modifications to MOD-032 Draft 3	

Answer	
Document Name	
Comment	

MOD-032 provides adequate clarity regarding DER modeling thresholds – Members of the SRC are aware of industry concerns that the currently proposed MOD-032 language could be construed to require modeling of individual DERs, regardless of size or impact to the BES. However, the SRC's understanding is that MOD-032 allows PCs and TPs to determine what degree of modeling granularity is needed as part of the modeling data requirements and reporting procedures that they jointly develop under Requirement R1.

The SRC's understanding is based on the language in Requirement R1 and on the structure of Attachment 1. More specifically, the drafting team's proposed structure for **Attachment 1, column 1, "steady state" item 9 Aggregate DER data** is similar to the existing structure used for **Attachment 1, column 1, "steady state" item 2 Aggregate Demand** (both items list a type of aggregate data, with subitems specifying more particular types of data). In addition, footnote 4 in Attachment 1 clarifies that the modeling data requirements and reporting procedures that are jointly developed under Requirement R1 will specify the required level of aggregation. To help alleviate industry concerns, the SRC requests that the drafting team clarify whether the SRC's understanding of this topic is correct.

Need to reinstate the Transmission Owner (TO) function – The TO has been removed from the modeling equation, yet there are times when there is no registered Distribution Provider (DP) and the Transmission Planner (TP) will still need to coordinate with the TO to obtain DER information. From a compliance perspective, there is a need to balance the responsibilities on both parties by requiring the TO to provide accurate and comprehensive DER data to the TP when there is no registered DP as illustrated below:

steady-state 2. Aggregate Demand [DP, TO]

steady-state 9. Aggregate Distributed Energy Resource (DER) data [DP, TO]

dynamics 5. Aggregate Demand [DP, TO]

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends adding Battery Energy Storage Systems Data [GO] to the dynamics column in Attachment 1.

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
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis
Answer	
Document Name	
Comment
In addition to supporting the IRC SRC comments, PJM understands and agrees with the proposed definition of a DER. However, we have concerns with the applicability of MOD-032 and DERs being defined (requesting additional clarification). For example, it would be beneficial to specify whether MOD-032 applies only to DER aggregations that are ≥20 MW with export capability to the Bulk Electric System (BES) or those that are 20 MW connected to 69 kV or above.
Likes 0	
Dislikes 0	
Response
Robert Jones - Seattle City Light - 1,3,4,5,6
Answer	
Document Name	
Comment
The proposed changes require entities to model aggregate DERs at substation buses. There needs to be a guideline or clarification on how to select a dynamic model for the aggregate DERs. Due to variety of devices on the system, the aggregate DERs would require entities to make assumptions on dynamic model parameters. Additionally, dynamic data may not be available for all equipment. What level of assumptions are reasonable and ensure the requirements of the standards are not violated? One entity’s assumptions may be different than other.
Likes 0	

Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	

Comment

Recommend this project be delayed and work in tandem with Project 2024-01 ROP changes and / or put on hold until the ROP changes are made. Otherwise, industry is being asked to approve unbounded definitions with impacts that cannot be quantified.

The MRO NSRF does not agree with the language contained in Item 9 of Attachment 1 because most DPs do not have detailed information on the aggregated output of DERs on their systems. While it is possible to supply information on the aggregated capability of those resources and the aggregated types (i.e., solar, battery, diesel generator, etc.) they do not have real time monitoring of those facilities or have the ability to provide aggregated models that might approximate what is possible to supply for BPS connected IBRs. To address our concerns, we offer the following changes to Item 9 and Footnotes 2 and 4 under Attachment 1.

9. Aggregate Distributed Energy Resource (DER) data [DP]

a. Location (bus from item 1)

b. Cumulative Real power capability name plate capacity

c. Percentage of DER by type (solar, battery, diesel generator, etc.)

d. DER capabilities related to ridethrough, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.

Footnote 2:

2. Aggregate Demand [DP]

a. Cumulative real and reactive power

b. Percentage of in-service status

The MRO NSRF supports the use of generic, aggregate DER models for analyzing the impact of “small” DERs as we believe this is adequate to reliably approximate and model the impact of “small” DERs. Even if the DP was able to provide discrete information concerning every DER on its system, it is unlikely their PC or TP would be able to use it in its planning model.

Therefore, the need for individual DER models should be reserved for “large” DERs as specified in the Planning Coordinator’s jointly developed (with its TPs) steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for their area.

Requirement R1 allows each TP to define what level of granularity is needed to reliably model DERs in its TP area. To obtain industry consensus, it would be helpful for the SDT to clarify and emphasize this as industry remains concerned that the language is open to interpretation.

To that end, the MRO NSRF recommends NERC host a Technical Conference like the one recently held in Washington DC to advance PRC-029 (generator ride-through for IBRs). More conversation is needed to obtain a meeting of industry minds. Once there is agreement as to what data is

needed to adequately model DERs, it will be easier for the SDT to propose draft language that reflects that common vision. In the absence of that, industry may continue to talk past each other and make little progress.

An existing framework that may serve as a model is that used for low impact BES Cyber Assets. While BES Cyber Assets are defined as assets that "would affect the reliable operation of the Bulk Electric System," they are not part of the BES itself. If "small (low impact) DERs are intended to be viewed the same way, it may be worthwhile to look at the compliance framework for "low impact" BES Cyber Assets and see whether and how some of these principles may be applied in designing a compliance framework for low impact DERs, particularly the absence of a requirement to maintain a discrete list of low impact cyber assets.

Attachment 1: Data Reporting Requirements

While Attachment 1, column 1, "steady-state," items 9b, 9c and 9d clearly fall under "Aggregate DER data," the proposed language could be interpreted as requiring explicit information for each individual DER. Therefore, the SRC requests the SDT clarify that the information being requested is to be provided at the aggregate level to avoid alternate interpretations. Sample language below:

b. Cumulative Real power capability

c. Percentage of DERs by type (solar, battery, diesel generator, etc.)

d. Cumulative DER capabilities related to ride-through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.

Likewise, while Attachment 1, footnote #2 clearly states that, "For purposes of this item [i.e., item 2], aggregate Demand is the gross Demand aggregated at each bus," the proposed language could be interpreted as requiring explicit information for each individual DER. Therefore, the SRC requests the SDT clarify that the information being requested is to be provided at the aggregate level to avoid alternate interpretations. Sample language below:

2. Aggregate Demand [DP]

a. Cumulative real and cumulative reactive power*

b. Percentage of in-service status*

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

ATC supports the comments developed by the MRO NSRF.

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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF), and the North American Generator Forum (NAGF) on question 4	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource, in line with EEI, does not agree with some of the components in Attachment 1 Item 9 because most DPs do not have detailed information on the aggregated output of DERs in line with the requirements in the subparts of this item. While it is possible to supply information on the reported aggregated name plate capacity of the DER resources and identify those aggregated resources by type (i.e., solar, battery, diesel generator, etc.), DPs do not have real time monitoring of those facilities, and thus cannot provide accurate information regarding their current capabilities or specific performance criteria. Eversource suggests the following changes in boldface: a. Location (bus **or buses** from item 1) **b. Real power capability Reported aggregate name plate capacity (i.e. inverter or machine) as provided to the Distribution Provider during the Interconnection Process. Note: *Resources that are not in continuous parallel operation are not included in the aggregate models provided. (e.g.: EVs (vehicle to grid operation), backup generation for non-grid purposes, etc.)*** **c. Reported aggregate name plate capacity by** DER type (solar, battery, diesel generator, etc.) **NOTE: Eversource, contrary to EEI, is in favor of the current language that makes up letter D, with a slight modification** **D. Estimated** DER capabilities related to ride through, voltage control and/or frequency control or information that can be used to infer those capabilities for modeling purposes.	
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
SMUD supports the comments provided by the MRO NSRF and believes that a technical conference would be beneficial to this project to help bridge the gap of technical differences on how DERs are tracked, monitored, and modeled.

Likes 0	
Dislikes 0	

Response
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment
WECC suggests changes to Requirement R4 to be consistent with other Standards (and Projects currently underway) by replacing “Electric Reliability Organization or its designee” with “Compliance Enforcement Authority (CEA)”. M4 and the VSLs would need adjustments as well if adopted. In Attachment 1- WECC suggests capitalizing “interconnection-wide” in first use in second sentence. Is there a “bus number, name, and/or identifier” for DER? If so, does the DP and TO “assign” or are they assigned by the TP and PC? There are several instances of terms being capitalized in the Attachment 1 listing of data reporting requirements that should not be capitalized as they are not defined. And other terms that are defined need capitalized (e.g. Real Power). “Ride-through” was recently defined in Order 901 efforts. Is the intent of the DT to use that definition? If not, what does term that mean? What does Aggregate DER mean versus DER? How would one define the bus number/name or aggregate?

Likes 0	
Dislikes 0	

Response
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	

Document Name	

Comment

EEI appreciates the changes made to Attachment 1 since the prior draft of this standard, however, what is contained in Attachment 1 still does not reflect what most DPs can provide at this time. We further note that even the Reliability Guideline titled DER Data Collection and Model Verification of Aggregate DER notes that DER interconnections generally do not contain requirements that include “high and low time-resolution data collection”, the guideline further notes that such change will take considerable time to implement and will require state regulator directives to accomplish given these resources fall outside of NERC’s jurisdiction. It is also important to recognize that existing resources, already interconnected to the distribution system, may never be able or otherwise obligated to provide the level of data and modeling envisioned.

EEI further notes that the above referenced guideline additionally recommends that TOs and DPs install expanded monitoring equipment that currently doesn’t exist; making compliance at the level envisioned not possible at this time. Moreover, DPs do not monitor these resources in real-time and most would need to deploy extensive upgrades to their system before they could provide the detailed information envisioned under MOD-032-2 Draft 3. Expectations that DPs will be capable of providing aggregate DER models that yield accurate disturbance ride through (i.e., ride-through, voltage control and frequency control) is impractical and goes beyond what is contained in FERC Order 901. Nevertheless, in the future after DPs have installed Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS) broadly, such details will be possible to provide but such requirements are impractical at this time.

To address our concerns, we suggest the following edits in boldface below:

Attachment 1; Item 1

EEI does not agree with the language contained in Item 9 of Attachment 1 because most DPs do not have detailed information on the aggregated output of DERs in line with the requirements in the subparts of this item. While it is possible to supply information on the reported aggregated Name Plate Capacity of the DER resources and identify those aggregated resources by type (i.e., solar, battery, diesel generator, etc.), DPs do not have real time monitoring of those facilities or have the ability to provide aggregated models that will accurately define performance during BPS system disturbances. Moreover, DPs are not DER owners, and therefore do not have models for DER resources. It is also important to note that DPs generally do not conduct EMT studies on DER interconnections or require such models be provided as a condition of interconnection. To address our concerns, we offer the following changes (in boldface) to Item 9 of Attachment 1 below to better define what DP can provide:

9. Aggregate Distributed Energy Resource (DER) data [DP]

a. Location (bus from item 1)

b. Reported Aggregate Name Plate Capacity as provided to the Distribution Provider during the Interconnection Process. Note: *Resources that are not in continuous parallel operation are not included in the aggregate models provided. (e.g.: EVs (vehicle to grid operation), backup generation for non-grid purposes, etc.)*

c. Reported Aggregate Name Plate Capacity by DER type (solar, battery, diesel generator, etc.)

d. Aggregated composite DER models that approximate the performance of aggregated DERs on their system.

Footnote 4:

For purposes of this item, the Distribution Provider to which **aggregated** DERs **are** connected **shall be responsible for providing aggregated DER composite model[s] using engineering judgement that contains generalized characteristics of the type of DERs identified by DER type under 9c to** the Transmission Owner.

Proposed New Footnote 5 to address the limitation TOs and DPs often have regarding detailed data for IBR and DER resources they do not own or have the regulatory authority to collect (for Item 10 Steady State column and Item 11 Dynamics column and Item 3 Short Circuit column)

For purposes of this item, Transmission Owners and Distribution Providers are limited in the information that they can provide to Planning Coordinators and Transmission Planners for modeling purposes. This includes but is not limited to models of individual unregistered IBR and DER resources they do not own or have the regulatory authority to collect.

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

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

The standard as written **places an unsustainable compliance burden** on TPs, TOs, TOPs and DPs. The standard does not address the challenges a NERC registered entity (TP/TO/DP) will experience with collecting DER data from behind the meter facilities connected to us as DPs or TOs. CEHE supports EEI's comments that the modifications made to MOD-32-1 continue to obligate DPs to provide detailed data that exceeds their ability to obtain. Unregistered DER owners have no obligation or requirement under NERC standards to provide data for modeling. Requiring DPs to provide modeling data for equipment TPs/DPs do not own and have no means of acquiring data will leave TP/DPs in a position where we may fail to comply with the standard through no fault of our own despite our best efforts. CEHE supports EEI's comments concerning DPs not having the capability to monitor DER performance such as voltage ride through, voltage control, and/or frequency control information that can be used to infer those capabilities for modeling purposes. CEHE also supports EEI's proposed changes to item 9 and footnote 4 modifications under Attachment 1.

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	

Tyler Schwendiman - ReliabilityFirst - 10

Answer	
Document Name	
Comment	

RF supports changing the applicability from Load Serving Entity to Distribution Provider.

This project needs to consider requirements from FERC Order 901 in any subsequent postings.

To address non-BES IBRs, we recommend aligning the Applicability Section with the registration efforts of “Project 2024-01 IBR Registration and Standards Applicability Glossary Update”.

Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	
Comment	

AZPS supports the comments submitted by EEI on behalf of their members:

EEI appreciates the changes made to Attachment 1 since the prior draft of this standard, however, what is contained in Attachment 1 still does not reflect what most DPs can provide at this time. We further note that even the Reliability Guideline titled DER Data Collection and Model Verification of Aggregate DER notes that DER interconnections generally do not contain requirements that include “high and low time-resolution data collection”, the guideline further notes that such change will take considerable time to implement and will require state regulator directives to accomplish given these resources fall outside of NERC’s jurisdiction. It is also important to recognize that existing resources, already interconnected to the distribution system, may never be able or otherwise obligated to provide the level of data and modeling envisioned.

EEI further notes that the above referenced guideline additionally recommends that TOs and DPs install expanded monitoring equipment that currently doesn't exist; making compliance at the level envisioned not possible at this time. Moreover, DPs do not monitor these resources in real-time and most would need to deploy extensive upgrades to their system before they could provide the detailed information envisioned under MOD-032-2 Draft 3. Expectations that DPs will be capable of providing aggregate DER models that yield accurate disturbance ride through (i.e., ride-through, voltage control and frequency control) is impractical and goes beyond what is contained in FERC Order 901. Nevertheless, in the future after DPs have installed Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS) broadly, such details will be possible to provide but such requirements are impractical at this time.

To address our concerns, we suggest the following edits:

Attachment 1; Item 1

EEI does not agree with the language contained in Item 9 of Attachment 1 because most DPs do not have detailed information on the aggregated output of DERs in line with the requirements in the subparts of this item. While it is possible to supply information on the reported aggregated Name Plate Capacity of the DER resources and identify those aggregated resources by type (i.e., solar, battery, diesel generator, etc.), DPs do not have real time monitoring of those facilities or have the ability to provide aggregated models that will accurately define performance during BPS system disturbances. Moreover, DPs are not DER owners, and therefore do not have models for DER resources. It is also important to note that DPs generally do not conduct EMT studies on DER interconnections or require such models be provided as a condition of interconnection. To address our concerns, we offer the following changes to Item 9 of Attachment 1 below to better define what DP can provide:

9. Aggregate Distributed Energy Resource (DER) data [DP]

a. Location (bus from item 1)

b. Reported Aggregate Name Plate Capacity as provided to the Distribution Provider during the Interconnection Process. Note: *Resources that are not in continuous parallel operation are not included in the aggregate models provided. (e.g.: EVs (vehicle to grid operation), backup generation for non-grid purposes, etc.)*

c. Reported Aggregate Name Plate Capacity by DER type (solar, battery, diesel generator, etc.)

d. Aggregated composite DER models that approximate the performance of aggregated DERs on their system.

Footnote 4:

For purposes of this item, the Distribution Provider to which aggregated DERs are connected shall be responsible for providing aggregated DER composite model[s] using engineering judgement that contains generalized characteristics of the type of DERs identified by DER type under 9c to the Transmission Owner.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	
Document Name	

Comment	
For question 3 above, no issue with the phased-in implementation approach and effective date. Disagreement with the DER definition and use of DP within definition, as with questions 1 and 2 above.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
Attachment 1, Dynamics column item 10 - seems to be missing the entity responsible. [DP?]	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Andy Thomas On Behalf of: John Sturgeon, Duke Energy , 5, 6, 1, 1; - Andy Thomas	
Answer	
Document Name	
Comment	
Duke Energy supports implementation of NAGF Attachment 1, Dynamics, Column 10 response (missing functional entity – DP). Duke Energy also supports implementation of EEI Question 4 responses.	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	
Document Name	

Comment
It is recognized that Requirement R1 and the revised Attachment 1 are intended to provide the PC/TP flexibility in developing data requirements and reporting procedures that align with local practices and needs, so long as they include the items listed in the Requirement R1 Parts. However, from a compliance perspective, how to satisfy the modeling requirements identified in MOD-032-2 Attachment 1, Steady State column item #9, part “C” (DER type (solar, battery, diesel generator, etc.)) is not entirely clear. This requirement needs be more clearly defined (either in the standard or in the Technical Rationale) so that entities can have confidence that their data requirements established to meet Requirement #1 are sufficient. Question for the SDT: is the expectation that compliance with Attachment 1, Steady State column item #9, part C could be satisfied with specific / discrete modeling or itemization of DER types within simulation models (i.e., several DER generator types added to each bus), an aggregate “composite of DER types” at each bus, or would documentation outside of the simulation models be acceptable? Or, would any of the above alternatives be acceptable from a compliance perspective? We did not identify any additional clarity offered on MOD-032-2 Attachment 1, Steady State column item #9, part C in the Technical Rationale document. One recommendation would be to expand on this item within the Technical Rationale to ensure clarity for compliance purposes. We identify the same concern above for MOD-032-2 Attachment 1, Dynamics column item #10 (Aggregate Distributed Energy Resource (DER) data including whether DER is subject to tripping in conjunction with UFLS and/or UVLS). This requirement needs be more clearly defined (either in the standard or in the Technical Rationale) so that entities can have confidence that their data requirements established to meet Requirement #1 are sufficient. For example, would documentation outside of the simulation models be sufficient to demonstrate “whether DER is subject to tripping in conjunction with UFLS and/or UVLS”?

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	

Comment
PG&E provides input that the Dynamics column item 10 seems to be missing the entity responsible as they are struck out in the redline [DP?].

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	

Comment
The various requirements in Table 1 all give the applicable functions for the requirements, e.g. TO, RP, GO, etc. However, all the designations have been removed for the new requirement 10 under the “dynamics” column in the “redline” version. Note that the DP designation shows up in the “clean” version but is shown as deleted in the “redline” version. In the Technical Rationale document in the section titled “Rationale for Applicability Section,” we appreciate the DT’s recognition of the industry’s concerns over unregistered entities having no compliance obligation to provide data to the TO/DP. However, the requirements are being left in place and the concern is basically being ignored because “the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would unnecessarily delay the implementation of DER data requirements.” This is basically a cop-out by the DT. While it is understood, and agreed, that modifying NERC registry criteria and registering new entities is beyond the scope of Project 2022-02, the DT should not be moving forward with attempting to place requirements on the industry that may not be implementable. If modifying NERC registry criteria and registering new entities is required to implement the new requirements, then the DT should notify NERC that they cannot move forward until this is done. Otherwise, the industry is being placed in a “no-win” situation in that they have requirements being enforced that they cannot meet. Remove the sub bullet related to the Distribution Provider. Like the response for question 1, removing the words “connected to the Distribution Provider’s system” doesn’t affect the definition and removes the confusion. If you are trying to use this to say it includes sub-transmission voltages, just say that; including DP language makes it difficult to figure out the intent.

Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation aligns with the NAGF comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

Referencing Footnote 4, the SDT's newly added content in the Technical Rationale states "previous references to data collection efforts or passing through data by the DP/TO from these unregistered entities was removed from the standard language as it could add compliance risk on the DP/TO without any compliance obligation on the unregistered entities." Despite this acknowledgement, the SDT goes on to state "there is great value in moving forward with the standard with the registered DP as the responsible entity for DER data as this will vastly improve the amount of data that is available to the TP/PC." The Technical Rationale further states "where an unregistered DP (an entity not meeting the NERC registration criteria) is interconnected to the system of a registered entity (DP or TO), the DP/TO should coordinate with the unregistered DP to ensure the availability of information associated with DER that may be connected to the unregistered DP's system" and that "this effort would be considered as a best practice, even if not specifically required by the MOD-032." By taking these passages in their entirety, the Technical Rationale not only considers these efforts as a best practice, but also expects that they be executed, which is essentially an obligation of inference. Simply put, there are expectations set in the Technical Rationale which are not established within the obligations, and that is type of compliance risk that goes beyond the acknowledgement made within the Technical Rationale. In addition, AEP does not believe that "best practices", well-meaning as they may be, should be included in a Technical Rationale. Rather, they should be provided in Reliability Guidelines as "recommended practices."

AEP continues to believe that the best path forward for this proposed standard would be for those entities providing DER data to be registered as Functional Entities. As is the case in existing standards where Generator Owners are obligated to provide similar data, entities who possess the needed DER data noted in the Attachment One revisions should likewise be registered and explicitly obligated to provide this data as well. While we are unsure if the existing Functional Entities classes are themselves sufficient, or if instead, a new class of Functional Entities might need to be considered and developed, the need nonetheless exists. NERC may wish to also consider the potential that such obligations could potentially cross Federal and State jurisdictional lines of responsibility, further illustrating the complexity-of and challenges-in developing obligations to obtain the DER data in the revised Attachment One.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation aligns with NAGF comments

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	

Document Name	
Comment	
FE supports EEI comments and edits made to Attachment 1 Criteria #9 steady-state entry which states: 9. Aggregate Distributed Energy Resource (DER) data [DP] a. Location (bus from item 1) b. Reported Aggregate Name Plate Capacity as provided to the Distribution Provider during the Interconnection Process. Note: Resources that are not in continuous parallel operation are not included in the aggregate models provided. (e.g.: EVs (vehicle to grid operation), backup generation for non-grid purposes, etc.) c. Reported Aggregate Name Plate Capacity by DER type (solar, battery, diesel generator, etc.) d. Aggregated composite DER models that approximate the performance of aggregated DERs on their system.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA would like to remind NERC that there is currently a data collection gap for entities that are not registered, as they are not required to submit data to their Distribution Provider or Transmission Owner. BPA suggests that NERC create a new registration type or other means to address the gap.	
Likes 0	
Dislikes 0	
Response	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	
Document Name	

Comment	
Thanks the SDT for their hard work and allowing us to provide feedback.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
1) For MOD-032-2, the “Aggregate Distributed Energy Resource (DER) data, including whether DER is subject to tripping in conjunction with UFLS and/or UVLS” in #10 of the “Dynamics” column of attachment 1 should probably be more clearly defined, as to what data is exactly required here? 2) For #1 of the “Short Circuit” column in MOD-032-2 attachment 1, should it also designate the responsibility of this to [DP] in addition to GO, RP, and TO and refer to foot note-4?	
Likes 0	
Dislikes 0	
Response	
Srikanth Chennupati - Entergy - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder
Standards Announcement
Project 2022-02 Uniform Modeling Framework for IBR

Additional Ballots and Non-binding Poll Open through October 10, 2024

Now Available

Additional ballots for **Project 2022-02 Uniform Modeling Framework for IBR** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, October 10, 2024** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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.

This posting affects Phase I of the project for proposed Reliability Standard MOD-032-2 and does not contemplate the SAR related to FERC Order No. 901; the Milestone 3, Part 1.

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, Laura Anderson (via email) or at 404-782-1870. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project Uniform Modeling Framework for IBR observer list” in the Description Box.

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404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Formal Comment Period Open through October 10, 2024

Now Available

A 45-day formal comment period for **Project 2022-02 Uniform Modeling Framework for IBR** is open through **8 p.m. Eastern, Thursday, October 10, 2024** for the following standard and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- 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.

This posting affects Phase I of the project for proposed Reliability Standard MOD-032-2 and does not contemplate the SAR related to FERC Order No. 901; the Milestone 3, Part 1.

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 standard and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 1-10, 2024.**

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

For more information or assistance, contact Senior Standards Developer, Laura Anderson (via email) or at 404-782-1870. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project Uniform Modeling Framework for IBR observer list” in the Description Box.



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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 AB 3 ST
Voting Start Date: 10/1/2024 12:01:00 AM
Voting End Date: 10/10/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 248
Total Ballot Pool: 292
Quorum: 84.93
Quorum Established Date: 10/10/2024 3:41:05 PM
Weighted Segment Value: 41.9

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	79	1	24	0.387	38	0.613	0	7	10
Segment: 2	7	0.7	6	0.6	1	0.1	0	0	0
Segment: 3	65	1	18	0.367	31	0.633	0	5	11
Segment: 4	15	1	3	0.3	7	0.7	0	3	2
Segment: 5	74	1	21	0.404	31	0.596	0	7	15
Segment: 6	44	1	9	0.281	23	0.719	0	6	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	3	0.3	3	0.3	0	1	0
Totals:	292	6.3	84	2.64	134	3.66	0	30	44

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Third-Party Comments
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
		Jesus Sammy	Denise		

1	Imperial Irrigation District	Alcaraz	Sanchez	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Dane Rogers	Negative	Third-Party Comments
4	Austin Energy	Tony Hua		None	N/A
1	Austin Energy	Thomas Standifur		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
6	Public Utility District No. 2 of Grant County, Washington	Glen Pruitt		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments

1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Negative	Third-Party

					Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Salt River Project	Mathew Weber		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		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
1	Long Island Power Authority	Isidoro Behar		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted

1	Black Hills Corporation	Travis Grablander		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Danielle Moskop	None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Third-Party Comments
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
6	Austin Energy	Imane Mrini		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		None	N/A
1	Duke Energy	Katherine Street		Negative	Third-Party Comments
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Negative	Third-Party

					Comments
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Kristen Eyman	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Third-Party Comments
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Duke Energy	John Sturgeon	Andy Thomas	Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Salt River Project	Sarah Blankenship		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A

5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party

					Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	SaskPower	Wayne Guttormson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
1	Entergy	Brian Lindsey	Kristen Long	Negative	Comments Submitted
4	Electricities of North Carolina	Marcus Freeman		Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
					Third-

5	Colorado Springs Utilities	Jeffrey Icke		Negative	Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party

					Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Third-Party Comments
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Third-Party Comments
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A

6	Western Area Power Administration	Jennifer Neville	Negative	Third-Party Comments
6	Xcel Energy, Inc.	Steve Szablya	None	N/A
5	LS Power Development, LLC	C. A. Campbell	None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan AB 3 OT
Voting Start Date: 10/1/2024 12:01:00 AM
Voting End Date: 10/10/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 243
Total Ballot Pool: 290
Quorum: 83.79
Quorum Established Date: 10/10/2024 4:08:27 PM
Weighted Segment Value: 45.81

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	78	1	26	0.426	35	0.574	0	7	10
Segment: 2	6	0.6	6	0.6	0	0	0	0	0
Segment: 3	64	1	18	0.375	30	0.625	0	5	11
Segment: 4	15	1	3	0.3	7	0.7	0	3	2
Segment: 5	75	1	21	0.412	30	0.588	0	7	17
Segment: 6	44	1	9	0.281	23	0.719	0	6	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	4	0.4	1	0.1	0	1	1
Totals:	290	6.1	87	2.794	126	3.306	0	30	47

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Third-Party Comments
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Third-Party Comments
		Jesus Sammy	Denise		

1	Imperial Irrigation District	Alcaraz	Sanchez	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Dane Rogers	Negative	Third-Party Comments
4	Austin Energy	Tony Hua		None	N/A
1	Austin Energy	Thomas Standifur		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
6	Public Utility District No. 2 of Grant County, Washington	Glen Pruitt		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A

5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
					Third-

5	Dairyland Power Cooperative	Tommy Drea		Negative	Party Comments
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Salt River Project	Mathew Weber		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A

2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Danielle Moskop	None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
6	Austin Energy	Imane Mrini		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		None	N/A
1	Duke Energy	Katherine Street		Negative	Third-Party Comments
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

5	Vistra Energy	Daniel Roethemeyer	David Vickers	Abstain	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Kristen Eyman	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Third-Party Comments
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Duke Energy	John Sturgeon	Andy Thomas	Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Salt River Project	Sarah Blankenship		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A

3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
6	AEP	Mathew Miller		Negative	Comments Submitted
3	AEP	Leshel Hutchings		Negative	Comments Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Affirmative	N/A

1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	SaskPower	Wayne Guttormson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A

5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
1	Entergy	Brian Lindsey	Kristen Long	Negative	Comments Submitted
4	Electricities of North Carolina	Marcus Freeman		Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Abstain	N/A
3	Entergy	James Keele		Negative	Comments Submitted
5	Salt River Project	Thomas Johnson		Negative	Comments Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeffrey Icke		Negative	Third-Party Comments
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
			LaKenya		

5	Florida Municipal Power Agency	Chris Gowder	Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal	Affirmative	N/A

			Mazza		
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 AB 3 NB
Voting Start Date: 10/1/2024 12:01:00 AM
Voting End Date: 10/10/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 228
Total Ballot Pool: 278
Quorum: 82.01
Quorum Established Date: 10/10/2024 5:18:56 PM
Weighted Segment Value: 41.57

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	22	0.423	30	0.577	13	12
Segment: 2	6	0.3	3	0.3	0	0	3	0
Segment: 3	60	1	16	0.41	23	0.59	9	11
Segment: 4	14	1	3	0.3	7	0.7	2	2
Segment: 5	71	1	18	0.409	26	0.591	10	16
Segment: 6	42	1	8	0.308	18	0.692	8	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	1	0

Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	7	0.4	4	0.4	0	0	2	1
Totals:	278	5.7	74	2.55	104	3.15	48	50

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	No Comment Submitted
5	AEP	Thomas Foltz		Negative	No Comment Submitted
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	No Comment Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Negative	No Comment Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	No Comment Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	No Comment Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	No Comment Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	No Comment Submitted
1	Imperial Irrigation District	Jesus Sammy	Denise	Affirmative	N/A

		Alcaraz	Sanchez		
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	No Comment Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	No Comment Submitted
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	No Comment Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	No Comment Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	No Comment Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	No Comment Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove	Dane Rogers	Negative	No Comment Submitted
4	Austin Energy	Tony Hua		None	N/A
1	Austin Energy	Thomas Standifur		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	No Comment Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	No Comment Submitted
6	Public Utility District No. 2 of Grant County, Washington	Glen Pruitt		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	No Comment Submitted

1	Omaha Public Power District	Doug Peterchuck		Negative	No Comment Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	No Comment Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	No Comment Submitted
5	Duke Energy	Dale Goodwine		Negative	No Comment Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	No Comment Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
1	Portland General Electric Co.	Brooke Jockin		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	No Comment Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	No Comment Submitted
5	New York Power Authority	Zahid Qayyum		Negative	No Comment Submitted
6	Salt River Project	Timothy Singh		Negative	No Comment Submitted
3	New York Power Authority	Richard Machado		Negative	No Comment Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	No Comment Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	No Comment

					Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Negative	No Comment Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	No Comment Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	No Comment Submitted
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Negative	No Comment Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	No Comment Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
3	Salt River Project	Mathew Weber		Negative	No Comment Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	No Comment Submitted
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	No Comment Submitted
1	Exelon	Daniel Gacek		Negative	No Comment Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	No Comment Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A

6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	No Comment Submitted
6	Black Hills Corporation	Rachel Schuldt		Abstain	N/A
1	Black Hills Corporation	Travis Grablander		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Negative	No Comment Submitted
5	Black Hills Corporation	Sheila Suurmeier		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	No Comment Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Danielle Moskop	None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
6	Entergy	Julie Hall		Negative	No Comment Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Negative	No Comment Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	No Comment Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	No Comment Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
6	Austin Energy	Imane Mrini		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	No Comment Submitted
3	Austin Energy	Lovita Griffin		None	N/A
					No

1	Duke Energy	Katherine Street		Negative	Comment Submitted
1	Georgia Transmission Corporation	Greg Davis		Negative	No Comment Submitted
5	Vistra Energy	Daniel Roethemeyer	David Vickers	Abstain	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Negative	No Comment Submitted
1	National Grid USA	Michael Jones		Negative	No Comment Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Kristen Eyman	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	No Comment Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	Duke Energy	John Sturgeon	Andy Thomas	Negative	No Comment Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	No Comment Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	No Comment Submitted
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	No Comment Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	No Comment Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Salt River Project	Sarah		Negative	No Comment

		Blankenship			Submitted
6	Constellation	Kimberly Turco		Negative	No Comment Submitted
5	Constellation	Alison MacKellar		Negative	No Comment Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	No Comment Submitted
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
6	AEP	Mathew Miller		Negative	No Comment Submitted
3	AEP	Leshel Hutchings		Negative	No Comment Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
10	ReliabilityFirst	Tyler Schwendiman		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	No Comment Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	No Comment Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	No Comment Submitted
3	Eversource Energy	Vicki O'Leary		Negative	No Comment Submitted

3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	No Comment Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	No Comment Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	No Comment Submitted
1	Hydro One Networks, Inc.	Emma Halilovic	Lidija Efremova	Abstain	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	SaskPower	Wayne Guttormson		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	No Comment Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski	Brandon Smith	Negative	No Comment Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	No Comment Submitted
1	JEA	Joseph McClung		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Negative	No Comment Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
1	New York Power Authority	Daniel Valle		Negative	No Comment Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	No Comment Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
					No

1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comment Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	No Comment Submitted
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	No Comment Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender	Kevin Schawang	Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	No Comment Submitted
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
1	Entergy	Brian Lindsey	Kristen Long	Negative	No Comment Submitted
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Abstain	N/A
3	Entergy	James Keele		Negative	No Comment Submitted
5	Salt River Project	Thomas Johnson		Negative	No Comment Submitted
1	Basin Electric Power Cooperative	David Rudolph		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	No Comment Submitted

6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	No Comment Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	No Comment Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Negative	No Comment Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	No Comment Submitted
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	No Comment Submitted
4	DTE Energy	Patricia Ireland		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	No Comment Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
1	Colorado Springs Utilities	Corey Walker		Negative	No Comment Submitted
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
1	Xcel Energy, Inc.	Eric Barry		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	No Comment Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A

6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
3	Black Hills Corporation	Josh Combs		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	No Comment Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	No Comment Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	No Comment Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	No Comment Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
5	Enel Green Power	Natalie Johnson		None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	No Comment Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	No Comment Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle		None	N/A

		McCartney Longo			
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	No Comment Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	JEA	Marilyn Williams		None	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	No Comment Submitted
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A

[redacted]

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:	Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements		
Date Submitted:	4/29/24 (Revised on October 15, 2024)		
SAR Requester			
Name:	Alex Shattuck, Jamie Calderon, JP Skeath (Revised by 2022-02 DT)		
Organization:	North American Electric Reliability Corporation (NERC)		
Telephone:	470-259-0109 (Alex Shattuck) 404-960-0568 (Jamie Calderon) 404-823-1365 (JP Skeath)	Email:	Alex.Shattuck@nerc.net Jamie.Calderon@nerc.net John.Skeath@nerc.net

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

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

What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

This Standards Authorization Request (SAR) is initiated by the North American Electric Reliability Corporation (NERC), with consultation of the Reliability Security Technical Committee, to address directives issued by the Federal Energy Regulatory Commission (FERC) in Order No. 901. FERC issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. FERC Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBRs), including both utility scale and behind-the-meter or distributed energy resources (DERs).

Within the Order are four milestones that include sets of directives to NERC. In the Order, FERC has directed NERC to propose new or modified standards to mitigate reliability gaps in the current NERC

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Reliability Standards related to IBRs. Specifically, FERC directed NERC to develop new or modified Reliability Standards to address the following four broad topic areas related to IBRs: (1) data sharing; (2) data and model validation; (3) planning and operational studies; and (4) performance.

In January 2024, NERC filed the initial **Standards Development Work Plan in Response to FERC Order No. 901** (hereafter referred to as the "Work Plan"). A current version of the Work Plan will be maintained here. The Work Plan discusses how NERC will develop Reliability Standards within (Milestones 2-4) to meet FERC's filing deadlines. This SAR addresses Milestone 3 of the Work Plan related to Reliability Standards for modeling and data sharing requirements to establish sufficient IBR model data and parameters to assure accurate representation of IBR performance within the models. Further, collaborative sharing of this information and the utilization of this information throughout the lifecycle of IBRs will also be established.

Milestone 3 of the Work Plan covers the development of data provisioning, parameters, and estimation requirements for IBRs. FERC Order No. 901 directives address three categories of IBR: (1) registered IBR, including sub-Bulk Electric System IBRs to be registered under NERC's revised Compliance Registry criteria; (2) unregistered IBR; and (3) IBR-DER, to distinguish registered bulk connected IBRs from unregistered bulk connected IBRs as well as the transmission connected IBRs from distribution-connected IBRs. To be clear, assets to be included as part of revisions to the Compliance Registry criteria ("category 2 type assets") are considered herein as "registered IBR." NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.

As often discussed within NERC recommendations and publications, the current paradigm of modeling and data sharing leaves the bulk power system (BPS) at a higher than necessary risk for unexpected and undesired IBR performance. Since 2016, approximately 15,000 MW of IBR have unexpectedly reduced output during NERC categorized disturbance events. None of the IBR facilities involved in these disturbances utilized models that could accurately represent the facility's performance during the disturbance event. These discrepancies between modeled and studied performance when compared to real-world performance are driven by current industry modeling practices and a dependence on generic IBR modeling throughout the lifecycle of the IBR facility.

NERC Modeling Guidance [1] states that additional model types, namely manufacturer-specific user-written models, should be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance. The deficiencies within the current state of model quality are well documented. As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases.

Revisions to data sharing expectations and the creation of a "NERC Approved Model Library" that allows the use of manufacturer-specific models in instances where generic modeling cannot represent the

[1] https://www.nerc.com/pa/RAPA/ModelAssessment/Documents/Dynamic%20Modeling%20Recommendations.pdf

Requested information
performance of the IBR are necessary to ensure BPS reliability through improvements to the inputs of current study practices.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System (BES) being addressed, and how does this proposed project provide the reliability-related benefit described above?):
This SAR addresses specific pieces of the NERC filed Work Plan related to Milestone 3 and addresses the various industry comments to meet the regulatory directives of FERC Order No. 901. This project shall coordinate with other relevant projects in developing standard language and meeting the FERC Order No. 901 directives. This Project will address FERC Order No. 901 directives related to aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project is intended to serve as a data sharing center point for many of the revisions being established within all of the 901-related projects. Performance of IBR during an event (grid disturbance) are identified and corrected within the Standards Development projects pertaining to Milestone 2 of the Work Plan. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). Similarly, revisions to model validation being drafted by the drafting team assigned the Milestone 3 Part 2 SAR, must also assure entities follow the uniform model framework established here.
Project Scope (Define the parameters of the proposed project):
The FERC Order No. 901 directives assigned to this SAR are outlined in the Detailed Description section below. The project scope shall address all those directives, and should consider the following objectives during the standards development process: 1. Modify applicable Reliability Standards (e.g. MOD-032, TOP-003, and IRO-010) to ensure the usage of a uniform framework for each Interconnection that includes a minimum modeling criteria consistent with NERC's Dynamic Modeling Recommendations, a registered modeling designee, and necessary data exchange requirements. The framework must require: a. The usage of a "NERC-Approved Model Library" (hereafter: "Model Library"). i. The Model Library will be developed and maintained by NERC and will be consistent with NERC's published Dynamic Modeling Recommendations. The Model Library will not prohibit the use of equipment-specific models in Interconnection-wide base cases. ii. The Model Library will be accessible to the general public. NERC will develop an open and transparent process for maintaining the library. iii. The Model Library will include recommendations to facilitate the exchange of neighboring entities' respective planning and operation models to be used in Interconnection-wide case creation and in other NERC Reliability Standards for IBR.

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iv. The Model Library will include recommendations regarding model usage depending on study type. v. The DT may consider documenting additional guidance for NERC related to maintaining a model library. b. Data specification and notifications for the data necessary to develop Interconnection-wide models and models for other reliability studies. Specifications must include: i. Provisions and a periodicity for new, modified, or changed equipment for any changes that alter the performance of the IBR, and ii. Provisions and a periodicity for unregistered IBRs and DERs that include estimation, aggregation, or other data submittal. c. Data exchange of models from the Model Library for Interconnection-wide model creation (i.e., system models in the language of FERC Order No. 901 (157, 161)) that most accurately reflects, according to manufacturer documentation, the behavior of each IBR during steady state, short-circuit, and dynamic conditions; d. Data exchange of estimated modeling data and parameters, estimation methods, and documented limitations of the availability of accurate data for unregistered IBR and DER as developed by Transmission Owners and Distribution Providers. 2. The drafting team shall ensure that implementation plans for new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap during implementation.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The project scope above will need to account for the specific directive text in FERC Order No. 901 to be successful. The drafting team should consider the specific language in the FERC directives, as well as any comments in the underlying FERC Order No. 901 proceeding that FERC directed NERC to consider as part of the standard development process. **FERC Order 901 Directives Assigned to this SAR:** NERC will maintain a current version of NERC Standards Development's Work Plan to Address FERC Order No. 901 on the NERC website under Reliability Standards Under Development. Included in this Work Plan is a list of the directives in FERC Order No. 901 and their associated mapping of each SAR

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

Requested information

submitted by NERC. The Work Plan will be updated should any mapping of FERC directives be reassigned due to ongoing work in the various Standards Development Projects. As of April 1, 2024, this SAR will address the following FERC Order No. 901 directives, with the scope of this SAR emphasized in **bold** where the Paragraph language is separated[3] across multiple projects:

1. **"Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate**; and (2) data and model validation for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate." (P 7)
2. **"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information ,and control settings for momentary cessation and ramp rates)** that accurately represent the registered IBRs **to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System."** (P 76)
3. "Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." (P 77)
4. **"As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models** that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P78)
5. "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." (P 86)
6. "Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System." (P 102)

[3] Other Projects will cover the non-bolded sections of the same Order Paragraph containing the directive.

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7. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." (P 104)
8. "To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters." (P 104)
9. "Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation." (P 105)
10. "In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters." (P 105)
11. "For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation." (P 106)
12. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided

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to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear." (P 108)

13. **"As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models** that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P 108)
14. **"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require the use of approved industry generic library IBR models** that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models." (P 122)
15. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies." (P 124)
16. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models." (P 125)
17. "**We also direct NERC to require** the generator owners of registered IBRs and **the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of** registered and **unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior**." (P 141)
18. "Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives." (P 141)
19. "Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the

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aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior)." (P141)

20. "Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives." (P 141)
21. "Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models." (P 141)
22. "Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System." (P 141)
23. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to be able to perform respective system studies." (P 146)
24. "**Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate** and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models." (P 157)
25. "**Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models)** and the validation of each respective system model." (P 161)

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26. "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." (P 226)
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The associated cost with implementation of a new standard is currently unknown, and the modifications necessary for each specific directive are also unknown though they are expected to vary based on DT outcome.
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 connected to the transmission system.
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 NERC Rules of Procedure Appendix 5A:
This Project should contain appropriate members representing the following Functional Entities: Balancing Authority Distribution Provider Generator Owner Generator Operator Planning Coordinator Reliability Coordinator Transmission Owner Transmission Operator Transmission Planner
Do you know of any consensus building activities[4] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
FERC Order No. 901 NERC Standards Development Work Plan in Response to FERC Order No. 901 Inverter-Based Resource Activities, Quick Reference Guide Distributed Energy Resource Activities, Quick Reference Guide IBR Registration Initiative, Quick Reference Guide
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)?
1. SARs:

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

Requested information
a. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation b. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision 2. Active Reliability Standards Projects: a. 2020-06 Verifications of Models and Data for Generators b. 2021-01 Modifications to MOD-025 and PRC-019 c. 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 (NERC Standards Development recommends assigning the SAR to this active project) d. 2022-04 EMT Modeling e. 2023-05 Modifications to FAC-001 and FAC-002 f. 2023-08 Modifications of MOD-031 Demand and Energy Data
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 with the benefits of using them. Since the directives of FERC Order 901 instruct NERC to develop new or modified standards, there were no other alternatives considered.

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

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☒ Draft SAR reviewed by NERC Staff	☐ Final SAR endorsed by the SC
☐ Draft SAR presented to SC for acceptance	☐ SAR assigned a Standards Project by NERC
☐ DRAFT SAR approved for posting by the SC	☐ SAR denied or proposed as Guidance document
Risk Tracking.	
☐ Grid Transformation	☐ Energy Policy
☐ Resilience/Extreme Events	☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

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:	Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements		
Date Submitted:	4/29/24 (Revised on October 15, 2024)		
SAR Requester			
Name:	Alex Shattuck, Jamie Calderon, JP Skeath (Revised by 2022-02 DT)		
Organization:	North American Electric Reliability Corporation (NERC)		
Telephone:	470-259-0109 (Alex Shattuck) 404-960-0568 (Jamie Calderon) 404-823-1365 (JP Skeath)	Email:	Alex.Shattuck@nerc.net Jamie.Calderon@nerc.net John.Skeath@nerc.net

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

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

What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

This Standards Authorization Request (SAR) is initiated by the North American Electric Reliability Corporation (NERC), with consultation of the Reliability Security Technical Committee, to address directives issued by the Federal Energy Regulatory Commission (FERC) in Order No. 901. FERC issued Order No. 901 on October 19, 2023, which includes directives on new or modified NERC Reliability Standard projects. FERC Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of inverter-based resources (IBRs~~);~~), including both utility scale and behind-the-meter or distributed energy resources (DERs).

Within the Order are four milestones that include sets of directives to NERC. In the Order, FERC has directed NERC to propose new or modified standards to mitigate reliability gaps in the current NERC

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Reliability Standards related to IBRs. Specifically, FERC directed NERC to develop new or modified Reliability Standards to address the following four broad topic areas related to IBRs: (1) data sharing; (2) data and model validation; (3) planning and operational studies; and (4) performance.

In January 2024, NERC filed the initial **Standards Development Work Plan in Response to FERC Order No. 901** (hereafter referred to as the "Work Plan"). A current version of the Work Plan will be maintained here. The Work Plan discusses how NERC will develop Reliability Standards within (Milestones 2-4) to meet FERC's filing deadlines. This ~~Standard Authorization Request~~SAR addresses Milestone 3 of the Work Plan~~,~~ related to Reliability Standards for modeling and data sharing requirements to establish sufficient IBR model data and parameters to assure accurate representation of IBR performance within the models. Further, collaborative sharing of this information~~,~~ and the utilization of this information throughout the lifecycle of IBRs will also be established.

Milestone 3 of the Work Plan covers the development of data provisioning, parameters, and estimation requirements for IBRs. FERC Order No. 901 directives address three categories of IBR: (1) registered IBR, including sub-Bulk Electric System IBRs to be registered under NERC's revised Compliance Registry criteria; (2) unregistered IBR; and (3) IBR-DER, to distinguish registered bulk connected IBRs from unregistered bulk connected IBRs as well as the transmission connected IBRs from distribution-connected IBRs. To be clear, assets to be included as part of revisions to the Compliance Registry criteria ("category 2 type assets") are considered herein as ~~"~~"registered IBR."~~.~~ NERC must file the Reliability Standards or definitions developed under Milestone 3 by November 4, 2025.

As often discussed within NERC recommendations and publications, the current paradigm of modeling and data sharing leaves the bulk power system (BPS) at a higher than necessary risk for unexpected and undesired ~~inverter-based resource (~~IBR~~)~~ performance. Since 2016, approximately 15,000 MW of IBR have unexpectedly reduced output during NERC categorized disturbance events. None of the IBR facilities involved in these disturbances utilized models that could accurately represent the facility's performance during the disturbance event. These discrepancies between modeled and studied performance when compared to real-world performance are driven by current industry modeling practices and a dependence on generic IBR modeling throughout the lifecycle of the IBR facility.

NERC Modeling Guidance [1] states that additional model types, namely manufacturer-specific user-written models, ~~must~~ should be used for local reliability studies, during the interconnection process and following commissioning to validate as-built performance – as well as through ongoing validation of performance. The deficiencies within the current state of model quality are well documented. As required by FERC Order No. 901, the development of positive sequence models based on an approved (standard) library of model types must be built into Interconnection-wide cases.

Revisions to data sharing expectations and the creation of a "NERC Approved Model Library" that allows the use of manufacturer-specific models ~~in addition to standard library (generic) models~~ in instances

[1] https://www.nerc.com/pa/RAPA/ModelAssessment/Documents/Dynamic%20Modeling%20Recommendations.pdf

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where generic modeling cannot represent the performance of the IBR are necessary to ensure BPS reliability through improvements to the inputs of current study practices.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System (BES) being addressed, and how does this proposed project provide the reliability-related benefit described above?):
This SAR addresses specific pieces of the NERC filed Work Plan related to Milestone 3 and addresses the various industry comments to meet the regulatory directives of FERC Order No. 901. This project shall coordinate with other relevant projects in developing standard language and meeting the FERC Order No. 901 directives~~among other projects (i.e., act as a clearing house to tie directive language to standard revisions), develop standard language (i.e., perform the normal duties of a standard development Project), and build upon other Milestones from FERC Order No. 901 Standards Projects to meet regulatory deadlines (i.e., maintain agility based on how FERC Order No. 901 related Projects proceed to meet the directive deadlines)~~. This Project will ~~also~~ address FERC Order No. 901 directives related to aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project is intended to serve as a data sharing center point for many of the revisions being established within all of the 901-related projects. Performance of IBR during an event (grid disturbance) are identified and corrected within the Standards Development projects pertaining to Milestone 2 of the Work Plan. However, any requisite changes to model data as a result of correcting IBR performance, must be communicated through a uniform model framework to assure all impacted entities and users of the approved models are adequately informed and provided updated models (as developed within this project). Similarly, revisions to model validation being drafted by the drafting team assigned the Milestone 3 Part 2 SAR, must also assure entities follow the uniform model framework established here.
Project Scope (Define the parameters of the proposed project):
The FERC Order No. 901 directives assigned to this SAR are outlined in the Detailed Description section below. The project scope shall address all those directives, and should consider the following objectives during the standards development process: ~~Modify MOD-032 to require the usage of a "NERC-Approved Model Library" (Hereafter: "The Model Library") that shall identify contains acceptable (and unacceptable) models, recommendations on which models should be used for each study, and include recommendations to facilitate the exchange of neighboring entities' respective planning and operation models and to be used in Interconnection-wide case creation and in other NERC Reliability Standards for IBR.~~ ~~This Model Library will be developed and maintained by NERC and include recommendations regarding model usage depending on study type. Updates on the Model Library development will be coordinated with the Drafting Team. The Drafting Team may solicit feedback comments of the NERC process from industry as needed.~~ ~~The Model Library will be accessible to the general public. NERC will develop an open and transparent process for maintaining the library.~~

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~~The Model Library will be consistent with NERC's published Dynamic Modeling Recommendations. The Model Library will not prohibit the use of equipment-specific models in Interconnection-wide base cases.~~
~~, primarily: Placeholder for DT guidance.~~

~~i. Industry-approved library models are sufficient for use in Interconnection-wide base case creation and interconnection-wide studies;~~

~~ii. For local reliability studies (e.g. performance during the interconnection process, model quality validation), equipment specific models should be used if standard library models (i.e. WECC Generic) cannot accurately represent the performance of the IBR. if generic models from the Model Library cannot accurately represent the IBR.~~

~~2.~~1. Modify applicable Reliability Standards (e.g. MOD-032, TOP-003, and IRO-010) to ~~require Planning Coordinators (PC), Transmission PlannersTPs, Reliability Coordinators (RC), Transmission OperatorsTOPs, and Balancing Authorities (BA) to~~ ensure the usage of a uniform framework for each Interconnection ~~that includes the usage of a "NERC-Approved Model Library" (hereafter:the Model Library"). which The uniform framework will~~that includes a minimum modeling criteria consistent with NERC's Dynamic Modeling Recommendations, a registered modeling designee, and necessary data exchange requirements. The framework must require:

a. The usage of a "NERC-Approved Model Library~~-~~" (hereafter: "Model Library").

i. The~~is~~ Model Library will be developed and maintained by NERC and will be consistent with NERC's published Dynamic Modeling Recommendations. The Model Library will not prohibit the use of equipment-specific models in Interconnection-wide base cases.

ii. The Model Library will be accessible to the general public. NERC will develop an open and transparent process for maintaining the library.

iii. The Model Library will include recommendations to facilitate the exchange of neighboring entities' respective planning and operation models to be used in Interconnection-wide case creation and in other NERC Reliability Standards for IBR.

iv. The~~is~~ Model Library will include recommendations regarding model usage depending on study type.

v. The DT may consider documenting additional guidance for NERC related to maintaining a model library~~Placeholder for DT guidance~~.

~~a.~~b. Data specification and notifications for the data necessary to develop ~~i~~Interconnection-wide models and models for other reliability studies. Specifications must include:~~;~~

i. ~~Specifications must include p~~Provisions and a periodicity for new, modified, or changed equipment for any changes that alter the performance of the IBR, and

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ii. ~~Specifications must include provisions for changes to an approved equipment-specific models for any changes that alter the performance of the IBR,~~

iii.ii. ~~Specifications must include p~~Provisions and a periodicity for unregistered IBRs and DERs that include estimation, aggregation, or other data submittal. ~~exchanging estimated aggregated unregistered IBR and DER data.~~

~~b.~~c. Data exchange of ~~generic~~ models from the Model Library for ~~i~~Interconnection-wide model creation (i.e., system models in the language of FERC Order No. 901 (157, 161)) that most accurately reflects, according to manufacturer documentation, the behavior of each IBR during steady state, short-circuit, and dynamic conditions; ~~;~~

~~c. A review and approval process for additional model types from the Model Library (other than generic model types) for other reliability studies;~~

d. Data exchange of estimated modeling data and parameters~~aggregated data~~, estimation methods, and documented limitations of the availability of accurate data for unregistered IBR and DER as developed by Transmission Owners and Distribution Providers ~~in Item 4~~.

~~3. Modify MOD-032 to require Generator Owners (GO) and Transmission Owners (TO) to follow the uniform framework developed in Item 2, specifically;~~

~~a. GO and TO of IBR must provide generic models from the Model Library for interconnection-wide model creation that most accurately reflect the behavior of each IBR during steady state, short-circuit, and dynamic conditions;~~

~~b. GO and TO of IBR must provide sufficient documentation regarding technical limitations and any inaccuracies as justification for the use of additional equipment-specific models.~~

~~i. For instance, a Corrective Action Plan created by a planner or operator to address model quality due to exceeded performance criteria (reference Milestone 3 Part 2 SAR), may should necessitate usage of an equipment-specific model, if available, instead of a generic model from the Model Library. .~~

~~ii. For instance, studied discrepancies between the generic model and performance or of the IBR or equipment-specific model demonstrated during the interconnection process may should necessitate usage of an equipment-specific model, if available, instead of a generic model. from the Model Library.~~

~~iii. For instance, discrepancies between the generic model and performance of the IBR during a disturbance (i.e. from a post-event analysis) may should necessitate usage of an equipment-specific model, if available. instead of a generic model from the Model Library. .~~

~~4. Modify TOP-003 and IRO-010 to require Transmission Owners and Distribution Providers to establish and implement data aggregation methods for unregistered IBR and DER. The SDT~~

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~~should consider including these methods in the TOP, BA, and RC data specifications these entities maintain. These standards must address:~~ ~~a. An estimate of the modeling data and parameters of IBR-DERs and unregistered IBRs,~~ ~~b. An explanation of the limitations of the availability of accurate data, and~~ ~~c. The method used for all estimations.~~ ~~5.~~2. The drafting team shall ensure that implementation plans for new or modified Reliability Standards related to Milestone 3 of the Work Plan are aligned and do not create a reliability gap during implementation.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[2] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The project scope above will need to account for the specific directive text in FERC Order No. 901 to be successful. The drafting team should consider the specific language in the FERC directives, as well as any comments in the underlying FERC Order No. 901 proceeding that FERC directed NERC to consider as part of the standard development process. **FERC Order 901 Directives Assigned to this SAR:** NERC will maintain a current version of NERC Standards Development's Work Plan to Address FERC Order No. 901 on the NERC website under Reliability Standards Under Development. Included in this Work Plan is a list of the directives in FERC Order No. 901 and their associated mapping of each SAR submitted by NERC. The Work Plan will be updated should any mapping of FERC directives be reassigned due to ongoing work in the various Standards Development Projects. As of April 1, 2024, this SAR will address the following FERC Order No. 901 directives, with the scope ~~for~~ of this SAR emphasized in **bold** where the Paragraph language is separated[3] across multiple projects: ~~this SAR emphasized in **bold** as appropriate:~~ 1. **"Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate**; and (2) data and model validation for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate." (P 7) 2. **"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state,**

[2] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[3] Other Projects will cover the non-bolded sections of the same Order Paragraph containing the directive.

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dynamic, and short circuit modeling information ,and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs **to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System."** (P 76)

3. "Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." (P 77)
4. **"As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models** that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P78)
5. "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." (P 86)
6. "Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System." (P 102)
7. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." (P 104)
8. "To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters." (P 104)

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9. "Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation." (P 105)
10. "In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters." (P 105)
11. "For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation." (P 106)
12. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear." (P 108)
13. **"As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models** that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions." (P 108)
14. **"Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require the use of approved industry generic library IBR models** that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models." (P 122)

Requested information

15. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies." (P 124)
16. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models." (P 125)
17. "**We also direct NERC to require** the generator owners of registered IBRs and **the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of** registered and **unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior**." (P 141)
18. "Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives." (P 141)
19. "Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior)." (P141)
20. "Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives." (P 141)
21. "Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to

Requested information
determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models." (P 141) 22. "Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System." (P 141) 23. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to be able to perform respective system studies." (P 146) 24. "**Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate** and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models." (P 157) 25. "**Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models)** and the validation of each respective system model." (P 161) 26. "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." (P 226)
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The associated cost with implementation of a new standard is currently unknown, and the modifications necessary for each specific directive are also unknown though they are expected to vary based on DT outcome.
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 connected to the transmission system.

Requested information
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 NERC Rules of Procedure Appendix 5A:
This Project should contain appropriate members representing the following Functional Entities: Balancing Authority Distribution Provider Generator Owner Generator Operator Planning Coordinator Reliability Coordinator Transmission Owner Transmission Operator Transmission Planner ~~Reliability Coordinator~~
Do you know of any consensus building activities[4] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
FERC Order No. 901 NERC Standards Development Work Plan in Response to FERC Order No. 901 Inverter-Based Resource Activities, Quick Reference Guide Distributed Energy Resource Activities, Quick Reference Guide IBR Registration Initiative, Quick Reference Guide
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)?
1. SARs: a. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 2: IBR Model Validation b. SAR titled: Federal Energy Regulatory Commission (FERC) Order No. 901 – Milestone 3, Part 3: IBR Modeling Revision 2. Active Reliability Standards Projects: a. 2020-06 Verifications of Models and Data for Generators b. 2021-01 Modifications to MOD-025 and PRC-019 c. 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 (NERC Standards Development recommends assigning the SAR to this active project) d. 2022-04 EMT Modeling e. 2023-05 Modifications to FAC-001 and FAC-002 f. 2023-08 Modifications of MOD-031 Demand and Energy Data

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

Requested information
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 with the benefits of using them. Since the directives of FERC Order 901 instruct NERC to develop new or modified standards, there were no other alternatives considered.

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

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
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

Project 2022-02 Uniform Modeling Framework for IBR

Action

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2022-02 Uniform Modeling Framework for IBR:
  - Initial formal comment and ballot period reduced from 45 calendar days to as few as 30 calendar days, with ballot pools formed in the first 10 calendar days and initial ballot and non-binding poll of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) conducted during the last 10 calendar days of the comment period. (Sections 4.7, 4.9)
  - Additional formal comment and ballot period (s) reduced from 45 calendar days to as few as 15 calendar days, with ballot(s) conducted during the last 10 calendar days of the comment period. (Section 4.12)
  - Final ballot period reduced from 10 calendar days to 5 calendar days. (Section 4.9)
- Authorize posting Project 2022-02 Uniform Modeling Framework for IBR proposed Reliability Standards MOD-032-2, IRO-010-5, TOP-003-8, and the associated Implementation Plan for an initial 30 calendar day formal comment and ballot period, with ballot pools formed in the first 10 calendar days, and initial ballots conducted during the last 10 calendar days of the comment period.

Background

The Federal Energy Regulatory Commission (FERC) issued Order No. 901 on October 19, 2023, which included directives on new or modified NERC Reliability Standard projects.[1] FERC Order No. 901 addresses a wide spectrum of reliability risks to the grid from the application of Inverter-Based Resources (IBRs), including both utility scale and behind-the-meter or distributed energy resources. Within Order No. 901, there are four milestones that include sets of directives to NERC. NERC Standards Development has identified three active projects (2020-06, 2021-01, and 2022-02) that are directly impacted by the associated FERC directives in Order No. 901.

In addition, to assist readers, please see the following additional documents drafted to help keep the NERC Milestone 3 projects organized.

- FERC Order No. 901 - Summary Information of Milestone 3
- FERC Order No. 901 - Summary Graphic of Milestone 3
- Standards Development Mapping of FERC Order 901 Directives and Other Guidance to Standards Development Projects

This one pager addresses Milestone 3 Project 2022-02 and the FERC directive covering the development of Reliability Standards to address concerns "related to IBRs at all stages of interconnection, planning, and operations.[2]" Among other things, FERC directed NERC to develop

[1] *Reliability Standards to Address Inverter-Based Resources,* Order No. 901, 185 FERC ¶ 61,042 (2023), available at eLibrary | File List.

[2] FERC Order No. 901 at P 25.

requirements addressing the provision of IBR and Distributed Energy Resource (DER) data to the entities responsible for the planning and operation of the Bulk-Power System.

All new or modified Reliability Standards and associated Implementation Plans addressing Milestone 3 of Order No. 901 must be filed with FERC by November 4, 2025. NERC Project 2022-02 addresses 24 FERC directives through modifications to MOD-032-2, IRO-010-5, and TOP-003-8 in addition to the development of the Implementation Plan.

At its November 13, 2024, meeting, the Standards Committee (SC) accepted the FERC Order No. 901 – Milestone 3, Part 1: Modeling and Data Sharing Requirements Standards Authorization Request and appointed this SAR to the 2022-02 Uniform Modeling Framework for IBR DT, as recommended by NERC staff.

NERC staff hosted a joint workshop from January 15-17, 2025, in Pheonix, AZ. During the workshop NERC staff and drafting team (DT) members reviewed the FERC directives associated with Milestone 3 and talked through concerns of industry prior to the development or modification of each standard(s) with its associated project.

A quality review for MOD-032-2, IRO-010-5, and TOP-003-8 and the associated Implementation Plan was conducted from March 14 to March 24, 2025, by NERC legal and engineering (Alain Rigaud, Lauren Perotti, Sarah Crawford, and JP Skeath), members of the DT (Hari Singh, CORE Electric Cooperative), PMOS Representatives (Donovan Crane, WECC), and industry members (Sarah Habriga, AEP; Todd Bennett, AECI; Ruth Kloecker, ITC Holdings; and Sean Bodkin, Dominion Energy).

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 governments that involves the reliability of the 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.

Summary

Project 2022-02 DT leadership and NERC staff request that the SC approve a waiver under section 16.0 of the SPM regarding the length of comment periods and ballots in order to meet the November 2025 regulatory deadline for Project 2022-02 as established by FERC.

Project 2022-02 DT leadership and NERC staff recommend that the SC shorten the initial formal comment and ballot period for all standards and definitions developed under Project 2022-02 from 45 calendar days to as few as 30 calendar days and any additional formal comment and

ballot period(s) from 45 calendar days to as few as 15 calendar days. In addition, Project 2022-02 DT leadership and NERC staff recommend shortening the final ballot of all standards and definitions from 10 calendar days to as few as five (5) calendar days.

NERC staff recommends the SC authorize initial formal comment and ballot period for Project 2022-02 Uniform Modeling Framework for IBR for a 30-calendar day formal initial ballot, with ballot pools formed in the first 10 calendar days, and initial ballots conducted during the last 10 calendar days of the comment period.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Minutes
Standards Committee Meeting

T. Bennett, chair, called to order the meeting of the Standards Committee (SC or the Committee) on April 16, 2025, at 1:02 p.m. Eastern. D. Love determined the meeting had a quorum. The SC member attendance and proxy sheets are attached as Attachment 1.

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

Introduction and Chair's Remarks
T. Bennett welcomed the Committee, guests, and proxies to the meeting.

Review January 22, 2025 Agenda (agenda item 1)
T. Bennett mentioned that agenda item 7 be removed due to the Standard Authorization Request (SAR) in response to comments not being posted for the Committee to review. The Committee approved the April 16, 2025, meeting agenda.

Consent Agenda (agenda item 2)
The Committee approved March 19, 2025 Standards Committee Meeting Minutes.

Project 2020-06 Verifications of Models and Data for Generators (agenda item 3)
S. Madan provided an overview and highlighted that this project is one of three active projects that have assigned directives from Federal Energy Regulatory Commission (FERC) Order No. 901. V. O'Leary recommended that the Milestone 3 posting be staggered to not overwhelm the subject-matter experts (SMEs) reviewing and providing comments to the formal ballots. J. Calderon agreed with the recommendation. M. Brytowski commented that the Milestone 3 projects are in a time crunch to meet their deadline of submittal to FERC by November 4, 2025. J. Calderon responded that more development time was needed due to the robust amount of information and extensive effort of coordination amongst the Milestone 3 projects. J. Johnson made a motion to:

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2020-06 Verifications of Models and Data for Generators:
  - Initial formal comment and ballot period reduced from 45 calendar days to as few as 25 calendar days, with ballot pools formed in the first 10 calendar days and initial ballot and non-binding poll of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) conducted during the last 10 calendar days of the comment period. (Sections 4.7, 4.9)
  - Additional formal comment and ballot period(s) reduced from 45 calendar days to as few as 15 calendar days, with ballot(s) conducted during the last 10 calendar days of the comment period. (Sections 4.9 and 4.12)

  - Final ballot period reduced from 10 calendar days to 5 calendar days. (Section 4.9)
- Authorize posting Project 2020-06 Verifications Model and Data for Generators Modeling definitions for an initial 25-calendar day formal comment and ballot period, with ballot pools formed in the first 10 calendar days, and initial ballots conducted during the last 10 calendar days of the comment period.

S. Bodkin seconded the motion.

The committee approved the motion with no oppositions and no abstentions.

Project 2021-01 System Model Validation with IBRs (agenda item 4)
S. Madan provided an overview and highlighted that this project is one of three active projects that have assigned directives from FERC Order No. 901. J. Johnson recommended that this project posting should be increased to 40 days. S. Bodkin commented that the next agenda item may require more posting time. J. Wike mentioned that original equipment manufacturers (OEMs) may need more time to conduct their feedback for the formal posting. J. Calderon responded that the three Milestone 3 projects leverage the same SMEs with tight deadlines, and it would be imperative for Project Management and Oversight Subcommittee (PMOS) liaisons, drafting team (DT), and developers communicate as projects work in parallel and in tandem. S. Bodkin made a motion to:

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2021-01 System Model Validation with IBRs:
  - Initial formal comment and ballot period reduced from 45 calendar days to as few as 35 calendar days, with ballot pools formed in the first 10 calendar days and initial ballot and non-binding poll of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) conducted during the last 10 calendar days of the comment period. (Sections 4.7, 4.9)
  - Additional formal comment and ballot period(s) reduced from 45 calendar days to as few as 15 calendar days, with ballot(s) conducted during the last 10 calendar days of the comment period. (Section 4.12)
  - Final ballot period was reduced from 10 calendar days to 5 calendar days. (Section 4.9)
- Authorize posting proposed Project 2021-01 System Model Validation with IBRs proposed Reliability Standard MOD-033-3, and its associated Implementation Plan for an initial 35-calendar day formal comment and ballot period, with ballot pools formed in the first 10 calendar days, and initial ballots conducted during the last 10 calendar days of the comment period.

V. O'Leary seconded the motion.

The committee approved the motion with no oppositions. P. MacDonald abstained.

Project 2022-02 Uniform Modeling Framework for IBR (agenda item 5)
S. Madan provided an overview and highlighted that this project is one of three active projects that have assigned directives from FERC Order No. 901. S. Bodkin asked if changing the posting date to 40 days would

conflict with the upcoming workshop. J. Calderon responded that the DT would not have enough time to review comments. S. Bodkin made a motion to:

- Approve the following waiver of provisions of the Standard Processes Manual (SPM) for Project 2022-02 Uniform Modeling Framework for IBR:
  - Initial formal comment and ballot period reduced from 45 calendar days to as few as 30 calendar days, with ballot pools formed in the first 10 calendar days and initial ballot and non-binding poll of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) conducted during the last 10 calendar days of the comment period. (Sections 4.7, 4.9)
  - Additional formal comment and ballot period (s) reduced from 45 calendar days to as few as 15 calendar days, with ballot(s) conducted during the last 10 calendar days of the comment period. (Section 4.12)
  - Final ballot period reduced from 10 calendar days to 5 calendar days. (Section 4.9)
- Authorize posting Project 2022-02 Uniform Modeling Framework for IBR proposed Reliability Standards MOD-032-2, IRO-010-5, TOP-003-8, and the associated Implementation Plan for an initial 30-calendar day formal comment and ballot period, with ballot pools formed in the first 10 calendar days, and initial ballots conducted during the last 10 calendar days of the comment period.

T. Pyle seconded the motion.

The committee approved the motion with no oppositions and no abstentions.

Errata to Reliability Standards CIP-006-7, CIP-007-7, CIP-008-7, CIP-009-7, and CIP-001-4 (agenda item 6)
A. Oswald provided an overview and highlighted that the correction is necessary to align with the defined term. Errata to be filed with FERC as they are still reviewing the submittal of the virtualization project. S. Bodkin made a motion to approve the errata changes to Reliability Standards CIP-006-7, CIP-007-7, CIP-008-7, CIP-009-7 and CIP-011-4 to correct the spelled-out term "Electronic Access Control or Monitoring System." T. Pyle seconded the motion.

The committee approved the motion with no oppositions and no abstentions.

Canadian-specific Revisions to EOP-012-3 – Extreme Cold Weather Preparedness and Operations (agenda item 8)
A. Oswald provided an overview. An observer provided an additional overview of the SAR and highlighted the key differences in the Canadian provinces. S. Bodkin asked if only Canadians are going to be solicited for the DT. A. Oswald confirmed that the makeup of the DT will be Canadian only. S. Bodkin questioned why a variance is only being requested for Canada and not also for the states that experience temperatures similar to Canada such as Wisconsin. S. Rueckert asked if the variance would result in a new version of the standard. L. Perotti responded that it would require a new version of the standard and an informational filing to FERC. P. MacDonald mentioned that not having FERC approval of the version may be an issue as his province follows only FERC approved standards. A. Oswald acknowledged P. MacDonald's comment and will address his comment offline. T. Bennett commented that the technical justification in the SAR is similar to the SAR comments. S. Bodkin commented that the technical justification is for jurisdictional issues. J.

Wike asked if the SAR undermines the comments from version 3 of the standard. An observer responded that the SAR does not undermine version 3 of the standard and their jurisdictional concerns were submitted throughout the entire balloting process for version 3. P. MacDonald made a motion to:

- Accept the Canadian-specific Revisions to EOP-012-3 – Extreme Cold Weather Preparedness and Operations SAR;
- Authorize posting of the SAR for 30-day formal comment period; and
- Authorize solicitation of drafting team (DT) members.

S. Rueckert seconded the motion.

The committee approved the motion. M. Brytowski (proxy for P. Metro) opposed and J. Wike abstained.

EOP-012-3 Cold Weather Update (agenda item 9)
J. Calderon provided an overview and highlighted that the FERC filing was made for the standard.

Projects Under Review (agenda item 10)
M. Brytowski reviewed the Project Tracking Spreadsheet. N. Santos reviewed the Project Posting Schedule and three-month outlook. A potential special call for Project 2020-06 was mentioned. S. Bodkin asked about the urgency of a special call. N. Santos responded that due to timing, the initial posting for the standard would not be able to wait until the May SC meeting. S. Bodkin commented that the waiver requested in agenda item 4 would only apply to the posting of the definitions. Applying the waiver would be a violation of the Rules of Procedure if used for the posting of standards. L. Perotti responded that there were two distinct items of action for agenda item 3. There would not be a violation of the Rules of Procedure in regard to the use of the waiver across the project, but the Committee could reconsider the earlier actions for agenda item 3.

Update Legal Update and Upcoming Standards Filings (agenda item 11)
A. Rigaud provided an update.

Adjournment
The meeting adjourned at 2:00 p.m. Eastern.

Standards Committee
2024 Segment Representatives

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Chair 2024-25	Todd Bennett* Managing Director, Reliability Compliance & Audit Services	Associated Electric Cooperative, Inc.		y
Vice Chair 2024-25	Troy Brumfield* Regulatory Compliance Manager	American Transmission Company		y
Segment 1-2024-25	Charlie Cook Lead Compliance Analyst	Duke Energy		y
Segment 1-2025-26	John Martinez Director- Transmission Operations	FirstEnergy		y
Segment 2-2024-25	Jamie Johnson Infrastructure Compliance Manager	California ISO		y
Segment 2-2025-26	Keith Jonassen Principal NERC Compliance Analyst	ISO-New England		y
Segment 3-2024-25	Claudine Fritz Principal Compliance Specialist	Exelon Corporation	Daniel Gacek	y
Segment 3-2025-26	Vicki O' Leary Director – Reliability, Compliance, and Implementation	Eversource Energy		y
Segment 4-2024-25	Marty Hostler Reliability Compliance Manager	Northern California Power Agency		y
Segment 4-2025-26	Patti Metro* Senior Grid Operations & Reliability Director	National Rural Electric Cooperative Associate	Mike Brytowski	y
Segment 5-2024-25	Terri Pyle* Utility Operational Compliance and NERC Compliance Office	Oklahoma Gas and Electric		y
Segment 5-2025-26	Josh Hale Commercial Services Manager	Southern Power Company		y

Segment and Terms	Representative	Organization	Proxy	Present (Member or Proxy)
Segment 6-2024-25	Sean Bodkin Senior Counsel	Dominion Energy		y
Segment 6-2025-26	Jennie Wike Compliance Lead	Tacoma Public Utilities		y
Segment 7-2024-25	Maggy Powell Principal Security Industry Specialist, Energy & Utilities	Amazon Web Services		y
Segment 7-2025-26	Venona Greaff* Senior Energy Analyst	Occidental Chemical Corporation		y
Segment 8-2024-25	Robert Blohm[1] Managing Director	Keen Resources Ltd.		y
Segment 8-2025-26	Kimberly Janas Counsel to the Attorney General	Illinois Attorney General's Office		y
Segment 9-2024-25	Paul MacDonald[1] Director Reliability Standards, Compliance and Enforcement	New Brunswick Energy and Utilities Board		y
Segment 9-2025-26	Daniela Cismaru[1] General Counsel	Market Surveillance Administrator		y
Segment 10-2024-25	Dave Krueger Senior Program Manager, Operations	SERC Reliability Corporation		n
Segment 10-2025-26	Steven Rueckert Director of Standards	WECC		y

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

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024

Anticipated Actions	Date
30-day formal comment period with initial ballot	April 17 – May 16, 2025
20-day formal comment period with additional ballot	July – August 2025
10-day final ballot	September 2025
Board adoption	October 2025

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):

Distributed Energy Resources (DER): Generators and energy storage technologies connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Generator Owner

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the responsible entity for each required item.

1.2. Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization (ERO).

1.3. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.3.1. Data format;

1.3.2. Level of detail to which equipment shall be modeled;

1.3.3. Case types or scenarios to be modeled; and

1.3.4. A schedule for submission of data at least once every 13 calendar months.

1.4. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If the responsible entity, as identified in Requirement R1 Part 1.1, is unable to gather unregistered Inverter-based Resource (IBR)[1] data or aggregate Distributed data and parameters and include an explanation of the limitations of

[1] As used in this standard, the phrase "unregistered IBR" refers to a Bulk-Power System connected IBR that does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

the availability of data, an explanation of the limitations of any data provided, and the method used for estimation.

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

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

   - Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. **Compliance Monitoring and Enforcement Program:** Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.
R2	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and

	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications;	short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource	circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service	short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet

	OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s)	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s)	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s)

	or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

MOD-032-2 – ATTACHMENT 1
Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[2] typically responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The joint Planning Coordinator /Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify the functional entity responsibility and data flow processes. The data reported shall be identified by the bus number, name, and/or identifier that is assigned in conjunction with the Planning Coordinator, Transmission Owner, or Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[3] [DP] a. real and reactive power* b. in-service status* 3. Generating and storage units[4] [GO, TO[5], RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above).	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[3] [DP] 6. Wind plant model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]] a. IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control 8. Static Var Systems and FACTS [GO, TO, DP] 9. DC system models [TO]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc.) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable	10. Aggregate Distributed Energy Resource (DER) data [DP, TO][6] a. DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. b. indication whether DER is subject to tripping in conjunction with UFLS or UVLS. 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
d. in-service status* 9. Aggregate Distributed Energy Resource (DER) data [DP, TO][6] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.) 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. This includes IBR, synchronous condensers, and pumped storage.
5. The Transmission Owner is the typical responsible entity for collecting and providing data for unregistered IBRs that are not DERs.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DER connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider’s system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner’s system.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024

Anticipated Actions	Date
30-day formal comment period with initial ballot	April 17 – May 16, 2025
20-day formal comment period with additional ballot	July – August 2025
10-day final ballot	September 2025
Board adoption	October 2025

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):

Distributed Energy Resources (DER): Generators and energy storage technologies connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-12**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.24.1.3 Generator Owner

   4.1.3 Load Serving Entity

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

   MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

   MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a

jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1~~.~~, including the responsible entity for each required item.

1.2. Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization (ERO).

~~**1.2.**~~**1.3.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

~~**1.2.1.**~~**1.3.1.** Data format;

~~**1.2.2.**~~**1.3.2.** Level of detail to which equipment shall be modeled;

~~**1.2.3.**~~**1.3.3.** Case types or scenarios to be modeled; and

~~**1.2.4.**~~**1.3.4.** A schedule for submission of data at least once every 13 calendar months.

~~**1.3.**~~**1.4.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If the responsible entity, as identified in Requirement R1 Part 1.1, is unable to gather unregistered Inverter-based Resource (IBR)[1] data or aggregate Distributed Energy Resource (DER) data, the responsible entity shall estimate the modeling data and parameters and include an explanation of the limitations of

[1] As used in this standard, the phrase "unregistered IBR" refers to a Bulk-Power System connected IBR that does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

the availability of data, an explanation of the limitations of any data provided, and the method used for estimation.

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. **Compliance Enforcement Authority**

   1.1. "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

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

   - Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. **Compliance Monitoring and Assessment Processes:** Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards..

~~1.3.~~

~~Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

~~1.4. Additional Compliance Information~~

~~None~~

~~Table of Compliance Elements~~

Violation Severity Levels

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-term Planning~~	~~Lower~~	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of

						the required components specified in Requirement R1.
R2	~~Long-term Planning~~	~~Medium~~	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving~~	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving~~	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided

			Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data	~~Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state,	~~Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state,	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data

			to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, ~~Load Serving Entity,~~ Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.

R3	~~Long-term Planning~~	~~Lower~~	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

			or Transmission Planner).	than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4	~~**Long-term Planning**~~	~~**Medium**~~	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

~~None.~~

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

MOD-032-012 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in *the* Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional *entity*[2] typically responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The joint Planning Coordinator /Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify the functional entity responsibility and data flow processes. The data reported shall be *as* identified by the bus number, name, and/or identifier that is assigned in conjunction with the *PC, TO*Planning Coordinator, Transmission Owner, or Transmission Planner*TP*.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSEDemand[3] [DP] a. real and reactive power*	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. -Those items may have different data provided for different modeling scenarios)*	dynamics *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	short circuit
b. in-service status* 3. Generating Units[3]and storage units[4] [GO, TO[5], RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc.) h. in-service status* h. 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status*	3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Demand [LSE]Aggregate Demand[3] [DP] 6. Wind Turbine Dataplant model (for plants with type 1 and type 2 wind turbines) [GO] 7. Photovoltaic systems [GO] 7. Inverter-Based Resource [GO, TO[5]] a. IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control 8. Static Var Systems and FACTS [GO, TO, LSEDP] 9. DC system models [TO] 10. Aggregate Distributed Energy Resource (DER) data [DP, TO][6] a. DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. b. indication whether DER is subject to tripping in conjunction with UFLS or UVLS. 10.11. Other information requested by the Planning Coordinator or Transmission Planner	2. Mutual Line Impedance Data- [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSEDP, TO, TSP]

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. -Those items may have different data provided for different modeling scenarios)*	dynamics *~~(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)~~*	short circuit
5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems -[TO] a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Aggregate Distributed Energy Resource (DER) data [DP, TO][6] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.) ~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and

~~to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).~~

~~The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).~~

~~Rationale:~~

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

~~Rationale for R1:~~

~~This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short-circuit data also required to perform short-circuit studies. The addition of short-circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.~~

~~In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.~~

~~This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.~~

~~This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:~~

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.
4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the

~~restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.~~

~~This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.~~

~~Rationale for R4:~~

~~This requirement will replace MOD-014 and MOD-015.~~

~~This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.~~

~~The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).~~

~~This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).~~

~~For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or~~

~~to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.~~

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. This includes IBR, synchronous condensers, and pumped storage.
5. The Transmission Owner is the typical responsible entity for collecting and providing data for unregistered IBRs that are not DERs.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DER connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	November 13, 2024
SAR posted for comment	May 5 – June 6, 2024
45-day formal comment period with initial ballot	April 17 – May 2, 2025

Anticipated Actions	Date
30-day formal comment period with initial ballot	April 17 – May 16, 2025
20-day formal comment period with additional ballot	July – August 2025
10-day final ballot	September 2025
Board adoption	October 2025

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection

2. **Number:** IRO-010-6

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.

4. **Applicability:**

   4.1. Reliability Coordinator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Transmission Operator

   4.6. Transmission Owner

   4.7. Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization;

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the DT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet one of the parts in Requirement Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet two of the parts in Requirement R1Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO- 010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	
6	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives.

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	November 13, 2024
SAR posted for comment	May 5 – June 6, 2024
45-day formal comment period with initial ballot	April 17 – May 2, 2025

Anticipated Actions	Date
30-day formal comment period with initial ballot	April 17 – May 16, 2025
20-day formal comment period with additional ballot	July – August 2025
10-day final ballot	September 2025
Board adoption	October 2025

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection

2. **Number:** IRO-010-~~5~~6

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.

4. **Applicability:**

   4.1. Reliability Coordinator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Transmission Operator

   4.6. Transmission Owner

   4.7. Distribution Provider

5. **Effective Date:** See Implementation Plan for Project ~~2021-06.~~2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to~~.~~:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization;

~~1.5.3~~1.5.4 Provisions to update or correct data and information, as applicable or necessary~~.~~;

~~1.5.4~~1.5.5 A mutually agreeable format~~.~~; and

~~1.5.5~~1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or ~~e-mail~~email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

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 the ~~mandatory and enforceable~~NERC 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~~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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its ~~-~~specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a ~~-~~specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
~~As defined in the NERC Rules of Procedure,~~ "Compliance Monitoring and Enforcement Program" ~~refers~~or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the ~~identification~~NERC Rules of Procedure) or the Commission-approved program of ~~the processes~~a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that ~~will be used to evaluate data or information~~is responsible for ~~the purpose of assessing performance or~~

~~outcomes~~performing compliance monitoring and enforcement activities with ~~the associated reliability standard~~respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the ~~SDT~~DT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet one of the parts in Requirement Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet two of the parts in Requirement R1Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-002 Technical Rationale

~~None.~~

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO- 010-1a (approval effective 5/23/11)	
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4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	
6	TBD	Adopted by NERC Board of Trustees	FERC order 901 Modifications

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
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Anticipated Actions	Date
30-day formal comment period with initial ballot	April 17 – May 16, 2025
20-day formal comment period with additional ballot	July – August 2025
10-day final ballot	September 2025
Board adoption	October 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization ;

1.5.4. Provisions to update or correct data and information, as applicable or necessary;

1.5.5. A mutually agreeable format;

1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the ERO;

2.5.4. Provisions to update or correct data and information, as applicable or necessary.

2.5.5. A mutually agreeable format.

2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (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 Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of

the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the Drafting Team (DT) is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7 Docket No.RD25-5-000	
8	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard for a formal 30-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	November 13, 2024
SAR posted for comment	May 17 – June 24, 2024

Anticipated Actions	Date
30-day formal comment period with initial ballot	April 17 – May 16, 2025
20-day formal comment period with additional ballot	July – August 2025
10-day final ballot	September 2025
Board adoption	October 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-~~7~~8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-~~03~~02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following:~~.~~

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization;

~~**1.5.3.**~~**1.5.4.** Provisions to update or correct data and information, as applicable or necessary;

~~1.5.4.~~1.5.5. A mutually agreeable format;

~~1.5.5.~~1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following~~.~~:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and

information, as applicable;

2.5.3. Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the ERO;

~~2.5.3.~~2.5.4. Provisions to update or correct data and information, as applicable or necessary.

~~2.5.4.~~2.5.5. A mutually agreeable format.

~~2.5.5.~~2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or ~~e-mail~~email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or ~~e-mail~~email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations

of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence

for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the ~~Standard~~ Drafting Team (~~S~~DT) is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

~~None.~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
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5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024~~TBD~~	Board Adopted~~Energy Assurance Modifications – Addition of Near-Term ERA.~~	Revisions under Project 2022-03~~ed~~
7	February 26, 2025	FERC approved TOP-003-7 Docket No.RD25-5-000	
8	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2022-02 Uniform Modeling Framework for IBR

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-6 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-8 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-5 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard(s)

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

- None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Distribution Provider
- Generator Owner
- Generator Operator
- Planning Coordinator
- Resource Planner
- Transmission Owner
- Transmission Operator
- Transmission Planner
- Transmission Service Provider

NERC Glossary of Terms

This section includes a newly defined term used in the NERC Reliability Standards. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, the defined term will be removed from the individual standard and added to the NERC Glossary of Terms.

Proposed New Definition:
Distributed Energy Resource (DER):
Generators and energy storage technologies connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an end-use customer that is supplied from a distribution system.

Background

As the penetration of DERs continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk-Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Further, in Order No. 901,[1] the U.S. Federal Energy Regulatory Commission ("FERC") found that it is imperative for NERC to develop new or modified Reliability Standards MOD-032, IRO-010, and TOP-003 to address reliability concerns "related to IBRs at all stages of interconnection, planning, and operations."[2]. Among other things, FERC directed NERC to develop requirements addressing the provision of IBR and DER data to the entities responsible for the planning and operation of the BPS. Detailed information on the specific FERC Order No. 901 directives addressed through this project is available in Project 2022-02 Consideration of Order No. 901 Directives.

Proposed Reliability Standard MOD-032-2 replaces the Load-Serving Entity as an applicable entity with the Distribution Provider and updates Attachment 1: Data Reporting Requirements with data specific to DERs and IBRs, consistent with addressing the FERC Order No. 901 directives. Proposed Reliability Standard MOD-032-2 also adds a new Part 1.2 in Requirement R1, which would require the Planning Coordinator and Transmission Planner to include in their data requirements and procedures requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization (ERO). New Requirement R2 Part 2.1 addresses estimation of unregistered IBR or DER data where actual data is not available, consistent with the directives in Order No. 901.
Revisions in the Reliability Standards TOP-003-8 and IRO-010-6 data specification standards specify that entities responsible for developing and distributing data specifications shall include requirements

[1] Reliability Standards to Address Inverter-Based Resources, Order No. 901, 185 FERC ¶ 61,042 (2023).
[2] Id. at P 25

for model submissions in accordance with the Criteria for Acceptable Models List maintained by the ERO.

General Considerations

In developing this implementation plan, the drafting team (DT) considered the time in MOD-032-2 that would be necessary to develop data requirements and reporting procedures, including identifying the proper reporting entity, for data related to IBRs, including unregistered IBRs and DERs. The DT also considered that the standard would become applicable to the Distribution Provider (DP) for the first time. Transmission Owners (TOs) and DPs would be expected to participate in PC/TP processes to change data reporting requirements related to DER and IBR developed during the 24 months prior to the effective date of Requirement R1 and should be able to start working on data collection processes and methods prior to the compliance dates of Requirements R2, R3, and R4. This timeline also allows for the development of new data estimation processes developed under MOD-032-2 Requirement R2 Part 2.1. Requirements adjusted in Reliability Standards IRO-010-5 and TOP-003-8 may not be practical to implement prior to full implementation of MOD-032-2, and therefore was set to the same timeline. One additional limitation the DT noted is the requirement for all FERC Order No. 901 directives to be fully implemented by January 1, 2030, including those covered by these standard revisions.

In summary, this implementation plan would provide a full 36 months for MOD-032 Requirements R2, R3, R4, IRO-010, and TOP-003 from FERC approval until data is required to be reported.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource is provided below. Where the DT 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.

Initial Performance Dates

Entities shall not be required to comply with Reliability Standard MOD-032-2 Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures as developed under Requirement R1 and Attachment 1, until 12 months after the effective date of Reliability Standard MOD-032-2.

Entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032-2 unless they are compliant with revised Planning Coordinator/Transmission Planner data requirements and reporting procedures under Reliability Standard MOD-032-2 Requirement R1.

Reliability Standard MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator and Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

Definition – Distributed Energy Resource (DER)

Where approval by an applicable governmental authority is required, the definition of DER shall become effective on the first day of the first calendar quarter that is after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard IRO-010-5

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard TOP-003-8

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1

Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard IRO-010-4

Reliability Standard IRO-010-4 shall be retired immediately prior to the effective date of Reliability Standard IRO-010-5 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard TOP-003-7

Reliability Standard TOP-003-7 shall be retired immediately prior to the effective date of Reliability Standard TOP-003-8 in the particular jurisdiction in which the revised standard is becoming effective.

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Unofficial Comment Form

Project 2022-02 Uniform Modeling Framework for IBR

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-02 Uniform Modeling Framework for IBR** by **8 p.m. Eastern, Friday, May 16, 2025.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Jordan Mallory (via email) or at 470-479-7538.

Background Information

As the penetration of distributed energy resources (DERs) continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk-Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System (BES). The North American Electric Reliability Corporation (NERC) System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Further, in Order No. 901 issued October 2023, The Federal Energy Regulatory Commission (FERC) directed the development of Reliability Standards to address concerns "related to Inverter-based Resources (IBRs) at all stages of Interconnection, planning, and operations." (Id. at P 25). Among other things, FERC directed NERC to develop requirements addressing the provision of IBR and DER data to the entities responsible for the planning and operation of the BPS. More information on the specific FERC Order No. 901 directives addressed through this project is available in the Project 2022-02 Consideration of Order No. 901 Directives.

Proposed Reliability Standard MOD-032-2 replaces the Load-Serving Entity (LSE) as an applicable entity with the Distribution Provider (DP) and updates Attachment 1: Data Reporting Requirements with data specific to DERs and IBRs, consistent with the FERC Order No. 901 directives. Proposed Reliability Standard MOD-032-2 also adds a new Part 1.2 in Requirement R1, which would require the PC and TP to include in their data requirements and procedures requirements for model submissions in accordance with the Criteria for Acceptable Models List maintained by the Electric Reliability Organization (ERO), which is NERC. New Requirement R2 Part 2.1 addresses estimation of unregistered IBR or DER data where actual data is not available, consistent with Order No. 901 directives.

Revisions in the TOP and IRO data specification standards specify that entities responsible for developing and distributing data specifications shall include requirements for model submissions in accordance with the Criteria for Acceptable Models List maintained by the ERO.

Questions

1. Do you agree with the proposed MOD-032-2 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system? If not, what entity would be in a better position to provide that data and add justification?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the proposed IRO-010-5 and TOP-003-8 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed DER definition? Please refer to the technical rationale, which provides rationale behind the drafting team's intent and previous definitions proposed. If you do not support the definition as proposed, please explain the changes that, if made, would result in your support.

   ☐ Yes
   ☐ No

   Comments:

5. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-5, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

   ☐ Yes
   ☐ No

   Comments:

6. Do you agree with the proposed ERO Approved Criteria for Acceptable Models document? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

   ☐ Yes
   ☐ No

   Comments:

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

   Comments:

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Violation Risk Factor and Violation Severity Level Justifications

Project 2022-02 Uniform Modeling Framework for IBR

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-02 Uniform Modeling Framework for Inverter-Based Resources (IBRs). 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 the Federal Energy Regulatory Commission (FERC)-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The drafting team applied the following North American Electric Reliability Corporation (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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R1 require model submission in accordance with the Criteria for Acceptable Models maintained by the ERO. This is similar to other sub-requirements in Requirements R1; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R1

Please refer to the VSL table below.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. "Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 in MOD-032-2. In addition, Requirement R2 added a sub-requirement requiring if entity is unable to gather unregistered IBR data or distributed energy resource(DER) data to complete an estimate. These modifications align with the medium risk requirement and therefore, the VRF remained medium.

VSL Justification for MOD-032-2, Requirement R2

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R3 were administrative in nature; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R3

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSLs for MOD-032-1, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

VSL Justifications for MOD-032-1, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional sub-requirement to Requirement R1. The proposed VSL was modified to reflect the additional sub-requirement. It does not have an 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 updated sub-requirement requires the responsible entity to follow the Criteria for Acceptable Models document maintained by the Electric Reliability Organization. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner,

of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.

VSL Justifications for MOD-032-1, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 and a sub-requirement was added requiring if entity is unable to gather unregistered IBR data or DER data to complete an estimate. The proposed VSL was modified to reflect the additional sub-requirement language. It does not have an 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 updated sub-requirement requires the entity if it is unable to gather unregistered IBR data or DER data to complete an estimate. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 3			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

VSL Justifications for MOD-032-1, Requirement 3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by replacing Load Serving Entity with Distribution provider. The proposed VSL was modified to reflect this modification. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

IRO-010-5

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for IRO-010-5, Requirement R1

Please refer to the VSL table located below.

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R2

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VRF Justification for IRO-010-5, Requirement R3

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R3

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSLs for IRO-010-5, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

VSL Justifications for IRO-010-5, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the addition sub requirement. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

TOP-003-8

VRF Justification for TOP-003-8, Requirement R1

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R1

Please refer to the VSL table located below.

VRF Justification for TOP-003-8, Requirement R2

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R2

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R3

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R3

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R4

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R4

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R5

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R5

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSLs for TOP-003-8, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.

VSL Justifications for TOP-003-8, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the addition sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for TOP-003-8, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-8, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R2. The proposed VSL was modified to reflect the addition sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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

NERC Project 2022-02 | MOD-032-2, TOP-003-8, and IRO-010-5
April 2025

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. It should be noted that Generator Owner (GO) applicability includes both Category 1 GO and Category 2 GO.

Additionally, the drafting team (DT) reviewed the dual applicability to Planning Authority (PA) and Planning Coordinator and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria is updated to use only a single term. The posted "Appendix 5B: Statement of Compliance Registry Criteria," dated June 27, 2024, still uses both terms and, arguably, the PA term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the DT excluded the explanatory language from MOD-032-2 Applicability Section.

Rationale for Distributed Energy Resource (DER) Definition

The approved standard authorization request (SAR) to revise MOD-032, submitted December 2021, noted that "it may be needed (based on the discretion of the DT) to add a definition for "Distributed Energy Resource (DER)" to the NERC Glossary of Terms" in conjunction with adding DER to Attachment 1, the main purpose of this SAR.[1] The DT found it necessary to draft a DER definition to clarify the usage of this term within the standard. Further, the DT recognized benefits of a Glossary of Terms definition to bring alignment and consistency of term usage across Reliability Standards. Inverter-Based Resources was recently defined in the Glossary of Terms under Project 2020-06 for a similar reason. Finally, the DT was comprised of team members with adequate experience to propose a definition, including members of the NERC SPIDERWG and IEEE 1547 working group.

The DT considered various DER definitions utilized in the industry and discussed in the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Terms and Definitions Working Document, including the six other definitions described in Appendix D which were not adopted by SPIDERWG. Through this review, the DT determined each of these seven definitions would benefit from refinement to be most suitable for application in MOD-032 and future reliability standards more broadly. It is expected that most reliability standard revision proposals related to DER would originate from the SPIDERWG. Thus, the DT intent was to propose a DER definition that aligned with the SPIDERWG working definition, which explicitly excludes demand response and clarifies what is in scope and out of scope with respect to where DER is connected, rather than the technology type).

[1] SAR title "MOD-032-1 Data for Power System Modeling and Analysis", submitted 12/15/2021. Available at: https://www.nerc.com/pa/Stand/Project202202ModificationstoTPL00151andMOD0321DL/2022-02_MOD-032%20SAR%20SPIDERWG_020122.pdf

The DT considered adopting a voltage threshold to define distribution. However, industry generally differentiates transmission from distribution based on the functional use of the system rather than technical specifications (e.g., voltage, active power, etc.). Setting aside the Bulk Electric System which has a clear NERC definition, defining electric facilities as either transmission or distribution is often based on State law or regulations, ISO/RTO tariff, and/or utility tariffs. The DT anticipates there are no conflicts in how applicable entities define distribution and transmission facilities for a given region, even if those definitions vary from region to region. Additionally, the DT considered an active power threshold to define DER and concluded that DER technologies can vary in size and a threshold might inappropriately exclude technologies that are DER[2]. At the same time, the DT understands that certain applications of DER data, for instance determining when or how a Transmission Planning (TP) or Planning Coordinator (PC) includes DER into planning processes (e.g., TPL-001), may include active power thresholds.

The DT considered defining DER based on the resource not being connected to the Bulk Power System (BPS), similar to the IEEE 1547-2018 definition that uses "not directly connected to the BPS" to describe DER. However, the NERC Glossary definition of BPS does not provide specificity that would enhance a definition of DER beyond an undefined term that is generally used in industry. The phrase "distribution system" was selected to expressly describe the type of electric facilities that would cause a resource to be defined as a DER, if interconnected to those facilities.

The DT recognizes that "distribution system" is not a NERC Glossary term and that the SPIDERWG proposed a definition.[3] The DT reviewed the SPIDERWG definition and concluded that it would not clarify the term DER. The SPIDERWG use of the term "transmission-distribution" interface within a definition of "distribution system" could be considered a circular reference that causes ambiguity. The DT is not proposing a definition of distribution system given any proposed definition could be of limited benefit for clarifying the proposed NERC Glossary term for DER.

Below is a summary of the rationale for the DT departing from each of the seven definitions when proposing a new DER definition.

SPIDERWG definition

After considering the SPIDERWG definition, the DT determined it provided a useful foundation but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term included transient types of DER power beyond generation and storage, and it included sources of back-up power that would have no potential grid impacts.

The DT chose to refer to generators and storage technologies specifically, rather than use the SPIDERWG language of "source", to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.). DER can use various technologies including synchronous machines, induction machines, and power inverters/converters (i.e., IBR). Different types of DER can

[2] NERC has published a study recommending that a zero MVA threshold be used when collecting DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

[3] SPIDERWG definition of "distribution system": The electrical facilities that are located behind a transmission-distribution transformer that serves multiple end-use customers. https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

utilize a wide range of energy sources including, but not limited to, natural gas, diesel, hydro, storage, wind, and solar. Additionally, the DT intention was to ensure that the scope included facilities "connected behind the meter of an end use customer" that may export Real Power to the power system or offset Real Power load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load. To exclude transmission connected load customers that have onsite generation or storage resources, the DER definition clarifies that the behind the meter customer "is supplied from a distribution system".

The DT included the language "in non-isolated parallel operation with the Bulk-Power System" to indicate that distributed energy resources with potential BPS reliability impacts are those that have electrical connectivity to the BPS. Resources that are only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BPS and, therefore, are not of interest from a BPS-reliability perspective. The DT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry. The DT intentionally avoided the term "directly connected" to differentiate electrical connectivity from an electrical connection point. The phrase "connected to the distribution system" speaks to electrical connectivity and the subsequent phrase "including those connected behind the meter of an end use customer" clarifies this connectivity includes resources directly connected to a customer system (i.e., behind the meter).

IEEE 1547-2018

The DT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the issues identified above. The DT incorporated the explicit reference to generation and storage aspect of the IEEE definition. Further, the IEEE concept of "capable of exporting active power to an EPS" informed the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the DT definition.

At the same time, the DT did not view the IEEE definition as suitable for the DT's intended use as written. The IEEE term qualifies the DER connection point as "not directly connected to a bulk power system" which the DT viewed as potentially ambiguous. Instead, the DT opted for the "connected to a distribution system" language to point to the electric system location, and how facilities at that location are classified, as a key concept in differentiating DER from other generators and energy storage technology. The DT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a NERC Glossary of Terms DER definition.

Federal Energy Regulatory Commission (FERC) Energy Primer

The DT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability use cases, the DT and SPIDERWG definitions target sources of electric power, with the DT narrowing this definition to be only sources "capable of providing Real Rower." After considering the FERC definition, the DT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)
NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the DT concluded it is too broad.

NERC DERTF
The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the DT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric System" which the DT views as overly broad.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be based on California legislation and includes energy efficiency, EVs, and demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the NERC Glossary of Terms.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition's exclusion of a large portion of DER (i.e. retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study.

Figure 1 below provides a graphic illustration of the DER definition and the intended scope of facilities that would fall under the proposed definition. Figure 2 below shows that the proposed DER and IBR definitions are compatible, but distinct. Some resources may be classified as DER, but not IBR; some resources may be classified as IBR, but not DER; some resources may be classified as both DER and IBR. Note that in Figure 2, "distribution-connected" is shorthand for connected to the distribution system and "bulk system-connected" refers to resources connected to the transmission system.

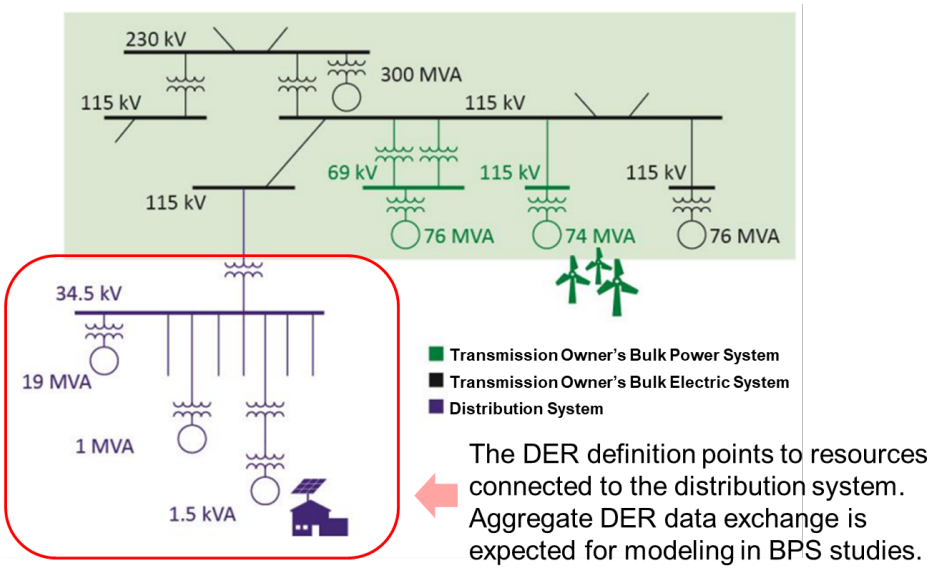


Figure 1: DER Definition Illustration

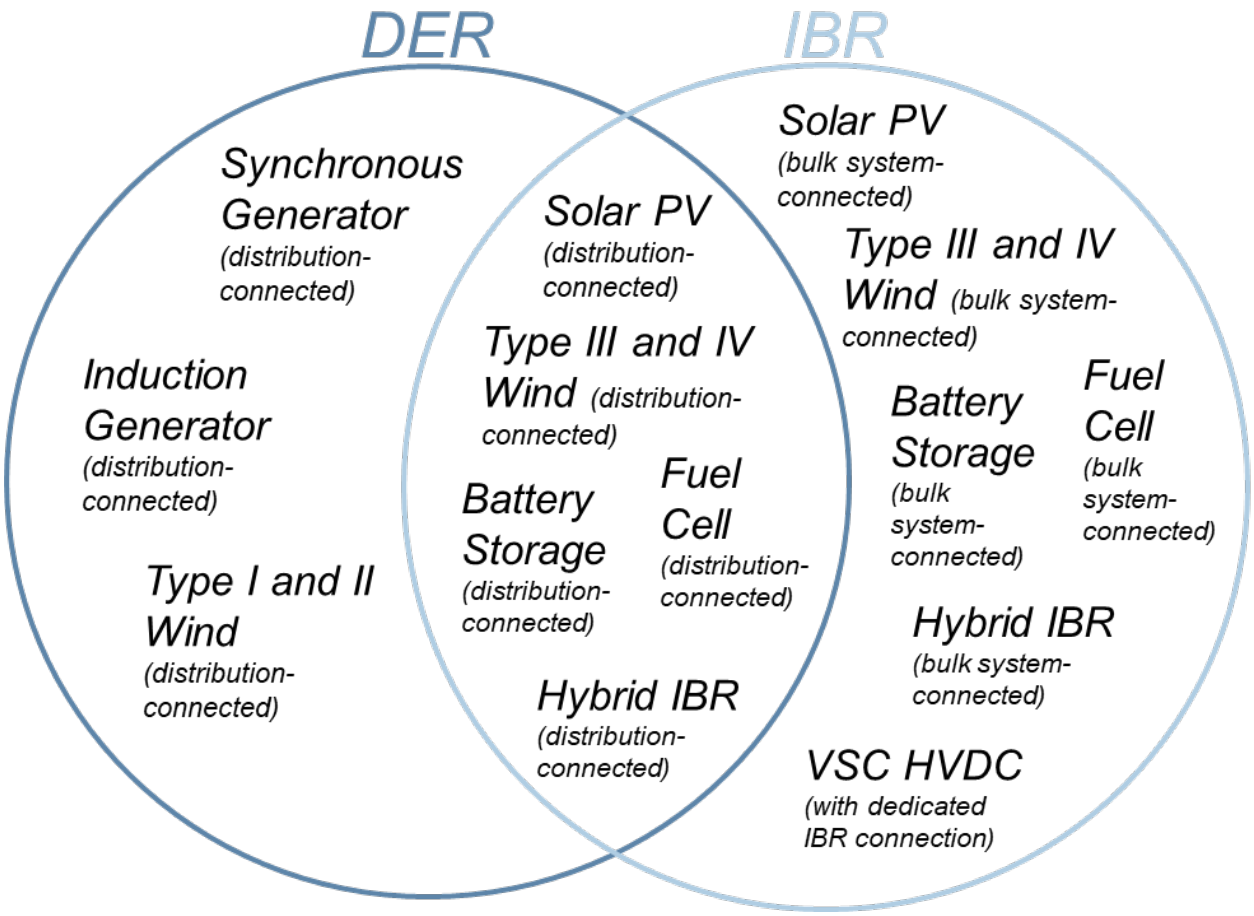


Figure 2: DER and IBR Definition Compatibility

Rationale for Modifications to Requirement R1

Requirement R1 was modified to require that PC and TP data requirements and reporting procedures include requirements for model submissions in accordance with a new ERO Approved Criteria for Acceptable Models document. The modifications are in response to FERC 901 directives.

The procedures resulting from Requirement R1 delineate data reporting responsibilities to avoid the potential for multiple submissions of the same data, which could lead to double counting of modeled elements.

FERC Order 901 directs NERC to develop reliability standards that require "the use of approved industry generic library IBR models".[4] However, pre-defining a limited set of models (i.e., a library of models) that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To align with industry practices while addressing the directives of the FERC Order, NERC staff incorporated elements from the NERC Dynamic Modeling Recommendations, including the proposed NERC Unacceptable Model List, into a newly developed ERO Approved Criteria for Acceptable Models document, rather than defining an

[4] FERC Order 901 at Paragraph 122.

inclusive model library. The DT supports the approach and views it as aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 NERC Industry Engagement Workshop.[5] For instance, Order 901 P125 requires "the sole use of nation-wide approved component generic library models" whereas workshop participants raised issues surrounding timelines for approving library models that reflect new IBR products, the accuracy of library models for certain products, timelines associated with updating library models, among other issues.

The ERO Approved Criteria for Acceptable Models document describes the required documentation and usability elements for planning and operational models. The ERO Approved Criteria for Acceptable Models document defines processes for modifying the criteria and the Unacceptable Models list. The DT views these processes as sufficient safeguards to prevent arbitrary or unvetted modifications being made to these documents referenced by the reliability standards.

The DT concluded that it would be most appropriate for NERC to maintain the ERO Approved Criteria for Acceptable Models as a separate document that could be referenced by reliability standards as needed rather than incorporate the criteria within reliability standards. This determination was based on the SAR language, time constraints for approval of FERC 901 Milestone 3 projects, and broader use of the new NERC document beyond MOD-032. For instance, while MOD-032 is an important application of the ERO Approved Criteria for Acceptable Models document, it will not be the only standard to reference the document. The DT considers maintenance as a separate document with NERC to be a better option for facilitating a unform modeling framework for both planning and operations in alignment with FERC Order 901 rather than incorporating concepts of the document into individualized Attachments for MOD-032 and other standards.

Rationale for Modifications to Requirement R2

Requirement R2 was modified to require estimation of modeling data if the Responsible entity (typically the Transmission Owner or Distribution Provider) is unable to gather required data. FERC Order 901 requires the provision of data related to unregistered-IBR and IBR-DER that in the aggregate have a material impact on the BPS.[6] If the data is estimated, Requirement R2.1 also requires the entity to provide an explanation of the limitations of the availability of data, an explanation of the limitations of any data provided by unregistered IBRs, and the method used for estimation.[7] The DT utilized the FERC Order language to broadly address the elements such an estimation must include, which was added as Requirement R2.1.[8] The requirement language intentionally uses the phrase "unable to gather" to mirror the FERC Order 901 language.

The DT views the introduction of these estimation methods as alleviating previous compliance obligation concerns around challenges in collecting data for DER connected to unregistered entities. The approach

[5] NERC_Industry_Engagement_Workshop–Reliable_IBR_Integration_and_Milestone_3_of_FERC_Order_901_Agenda
[6] FERC Order 901 at P104 and P105
[7] For instance, limitations on data gathering could result from legal or contractual prohibitions on requesting certain data.
[8] FERC Order 901 P104: "if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation."

directed by FERC is flexible as to whether the underlying unregistered IBR and DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP and TO applying a combination of approaches to source the data. The PC and TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

While the FERC Order 901 directives only addressed IBR-DER, meaning that DER technologies based on induction generators or synchronous generators are not explicitly addressed, the DT found it practical to have a consistent estimation framework applicable for all DER technologies when DER data cannot be gathered. Therefore, R2 was intentionally written to have requirements for estimating DER data regardless of the technology type, when an applicable entity is unable to gather the data. The approach FERC directed NERC to use forms the basis for this uniform approach.

Given the challenges with collecting complete and accurate DER data, the DT would still recommend that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would delay the project beyond the FERC Order 901 Milestone 3 timeline. The DT considered adding “UFLS-Only Distribution Provider” to MOD-032-2 applicability to reduce (but not necessarily eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, adding UFLS-Only Distribution Provider to the applicability would not be appropriate at this time based on consultation with NERC Legal staff.

Rationale for Modifications to Attachment 1

MOD-032-2 Attachment 1: Data Reporting Requirements was updated with data specific to IBR and DER.

The DT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with items are only presented in one column (i.e., some sub-bullets are only listed in the “steady state” column even though the data is also relevant to “dynamics” and/or “short circuit”). This long-standing approach was made explicit in footnote 1.

The format of Attachment 1 was modified to minimize replicating footnotes applicable to multiple items by adding a new footnotes section (Attachment 1 Data Reporting Requirements Footnotes) to the document. Along with the reformatting, language was added to the introductory paragraph to clarify that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1.

Modifications for IBR

To incorporate IBR within Attachment 1, “and storage units” was added to generating units in the steady-state column under item 3. “Generating units” already incorporates IBR generators such as solar and wind. Storage is typically not classified as a generation resource because it has no primary energy source and consumes more energy than it injects when considering losses. Therefore, the DT found it necessary to include storage explicitly. Footnote 4, associated with “Generating units and storage”, was also updated to clarify IBR as an applicable technology for the item.

The dynamics column was updated to replace "photovoltaic systems" (PV) with "Inverter-Based Resources" under item 7. IBR encompasses PV, resulting in PV technology still being included under this new item.

The three following sub-items were added to dynamics item 7 based on specific language from the FERC Order 901, Paragraph 141.[9]

- IBR capabilities related to momentary cessation,
- Tripping, and
- Ride-through

"Frequency control" was added as a sub-item because frequency response of IBR is important for studying system reliability. For instance, a 2024 NERC Lessons Learned report shows how IBR frequency response can affect system performance.[10] Frequency control encompasses primary frequency response, fast frequency response (e.g., IEEE 2800-2022, Subclause 6.2), and potentially other frequency responsive controls (e.g., "grid-forming" virtual synchronous machine controls).

In order to clarify dynamics item 6, "wind plant model", to not overlap with the new IBR item 7, type 1 and type 2 wind turbines are specifically called out under item 6. These technologies are not IBR.

Footnote 5 was added to clarify that the TO will typically be responsible for unregistered IBR that are not captured in DER modeling data.

Modifications for DER

Item 9, "Aggregate Distributed Energy Resource (DER) data" was added to the steady state column with location, real power capability, and DER type (solar, battery, diesel generator, etc.) specified as required subitems. The DT selected these subitems as the minimum information needed to use data and make assumptions for power system modeling and analysis.

The intent is that relevant DER data be available and represented in models of the interconnected transmission system consistent with the NERC approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum information needed to reasonably represent DER in transmission system models. "Aggregate DER" is added as new item 9 to indicate aggregate DER, rather than individual DER facilities, would be represented in most PC/TP study models.[11] The word "aggregate" was specifically added to Attachment 1 to clarify this point based on industry comments and to align with FERC Order 901. However, Requirement R1 provides the PC and TP great flexibility in developing data requirements and reporting

[9] FERC Order 901, P141 states that IBR and IBR-DER data must include "momentary cessation and/or tripping, and all ride through behavior."
[10] NERC, Lessons learned, Incorrect IBR Primary Frequency Response Logic Caused Negative ACE. Available at: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20240501_Incorrect_IBR_Primary_Frequency_Response_Logic_Caused_Negative_ACE.pdf
[11] In certain circumstances (e.g., very large DER), a TP or PC may decide to represent individual DER. However, the DT anticipates most DER information will be aggregated based on PC and PC planning criteria.

procedures that align with local practices and needs, in addition to the required items listed in the Requirement R1 Parts. Given industry comments on DER data availability, and FERC Order 901 directives, a process is needed for estimating DER data when an entity is unable to gather it. The process for estimating those values is referenced in Requirement R2 Part 2.1.

Footnote 3, associated with "aggregate demand", was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DER is not consistent with a modeling framework that explicitly represents DER.

Dynamics item 5, previously "demand", was updated to be "aggregate demand" to be consistent with the steady state column and general industry practices of modeling load dynamics for aggregate demand (e.g., composite load model).

Dynamics item 10 was updated to include "Aggregate Distributed Energy Resource (DER) data" along with the subitems: "DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control"; and "indication whether DER is subject to tripping in conjunction with UFLS or UVLS"

Momentary cessation, tripping, and ride-through of aggregate DER is needed for dynamics studies. For instance, NERC's Lessons Learned, LL20220401 "Distributed Energy Resource Performance Characteristics during a Disturbance" provided information following the loss of 300 MW of DER following a system fault. [12] The report indicated that, "There is a need to understand how distribution system connected generation, and loads will behave and how they can accurately be modeled under expected system contingencies. Entities should know the behavioral characteristics of DER inverters on their system (both new and old) as well as their number, capabilities, and locations and then report that information to their Balancing Authorities and Reliability Coordinators so their models can be accurate".

Voltage control of DER can alter the exchange of reactive power between distribution and transmission systems and may affect the results of reliability studies. Examples are described in the approved Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources.

Frequency control must be accounted for because DER interconnection under different standards (e.g., IEEE 1547-2003 versus IEEE 1547-2018) have different frequency response characteristics that may affect dynamics study results. Frequency control in this case typically refers to the frequency-droop characteristic outlined in IEEE 1547-2018, Subclause 6.5.2.7 and adopted in many jurisdictions. However, should other DER frequency controls become common in industry, those would also fall under this category.

As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is

[12] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220401_DER_Performance_During_a_Disturbance.pdf

vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DER subject to each UVLS/UFLS tripping stage should be identified.

Inferring DER Capabilities

Item 10 in the dynamics column indicates that aggregate DER dynamics modeling data may need to be inferred due to data availability and practical limitations. As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DER may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DER installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate Ride-through characteristic representation for DER in that area could be inferred by the in-service date of the DER. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics. Where applicable, similar assumption can be made for unregistered IBR.

Entity responsibilities and coordination

Footnote 6 provides additional distinctions that DER connected through a DP (directly connected to a registered DP, connected to an unregistered DP that is connected to a registered DP, or behind the meter of an end-use customer of either) should be reported by that DP. Further, the TO will be responsible if there is no system owned by a registered DP between the DER connection point and TO system. This clarification is necessary to reduce the possibility of DER on the system being unaccounted for by any entity. The DT was responsible for the FERC Order 901 directive requiring an entity to be identified when DER had no registered DP.

It should be noted that the MOD-032-2 modifications do not change the classification of unregistered IBR or DER to become BES facilities subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about unregistered IBR or DER that are connected to their systems so they can be properly represented in Interconnection-wide cases. There are already existing requirements for DPs (or TOs) to provide information about load connected to their systems. Like load, unregistered IBR and DER are not generally considered to be BES facilities. However, BES reliability assessments require an accurate representation of aggregate load, unregistered IBR, and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient data is available to the PC/TP so that appropriate unregistered IBR and DER representations can be included in their BES reliability assessments as required by FERC Order 901 and system planning needs.

IRO-010-6 – Reliability Coordinator Data Specification and Collection; and TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

The DT reviewed existing IRO-010 and TOP-003 versions and found that both standards had broad requirements language that encompassed generation and storage resources, including IBR. Nevertheless, to ensure no ambiguity that FERC Order 901 requirements are met, the DT included explicit references to IBR-specific data and parameters and pointed to the ERO Approved Criteria for Acceptable Models.

Rationale for Modifications to add "IBR-specific data and parameters"

The phrase "IBR-specific data and parameters" was added to the following requirements:

- IRO-010-6 Requirement R1 Part 1.1
- TOP-003-8 R1 Requirement Part 1.1
- TOP-003-8 Requirement R2 Part 2.1

These modifications were made in response to FERC Order 901 directives related to the inclusion of IBRs in operations models.[13] The phrase "IBR-specific data and parameters" in the revised IRO-010-06 and TOP-003-8 is intended to reflect what FERC describes in the order as "IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions".

Rationale for Modifications to add reference to ERO Approved Criteria for Acceptable Models

"Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization" was added to the following requirements:

- IRO-010-6 Requirement R1 Part 1.5.3
- TOP-003-8 Requirement R1 Part 1.5.3
- TOP-003-8 Requirement R2 Part 2.5.3

These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of operations models. The ERO Approved Criteria for Acceptable Models specifies further requirements as to what is needed for accurate models that are useful for the types of analysis specified by FERC in Order 901.

[13] FERC Order 901 Paragraph 122 and Paragraph 161

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of FERC Order 901 Directives

Milestone 3: Project 2022-02 Uniform Modeling Framework for IBR
April 2025

On October 23, 2023, FERC issued a Final Rule, Order No. 901, directing the North American Electric Reliability Corporation (NERC) to develop new or modified Reliability Standards that address aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project has a FERC regulatory deadline of November 4, 2025. Below provides the directives from FERC Order 901 along with the drafting team's (DT's) consideration of the directives.

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
P7. "… Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate…"	IRO-010 MOD-032 TOP-003	A timeline has been drafted to meet the regulatory deadline of November 4, 2025. Completed tasks listed below. • An industry workshop completed January 14-17, 2025. (outreach) • Many virtual drafting team meetings completed weekly from January – March 2025. (publicly posted) • In-person DT completed February 11-13, 2025. (publicly posted) • Industry Webinar March 6, 2025. (publicly posted) • DT outreach with trade groups and entities March 3 – 14, 2025 • Industry comment and ballot period April 17 – May 16, 2025. (publicly posted)

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
		• A second industry workshop scheduled for June 3-5, 2025. (publicly posted)
P76. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information, and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System. As several commenters indicate, ensuring the sharing of appropriate IBR modeling data is critical to create and maintain the models used in reliability studies, and in turn to ensure that Bulk-Power System transmission planners or operators are able to plan for, operate, and reliably integrate IBRs onto the Bulk-Power System."	IRO-010 MOD-032 TOP-003	**Theme:** IBR/Generator Owner to provide specific modeling data. IRO-010 and TOP-003: • While TOP-003 and IRO-010 allow any data to be requested, the DT felt it was important to add "IBR-specific data and parameters" specifically to IRO-010-6 Requirements R1 subpart 1.1 and TOP-003-8 Requirement R1 subpart 1.1 and Requirement R2 subpart 2.1 to ensure it is clear what data may be specifically requested to address FERC Order 901. In addition, IBR encompasses IBR-DER, and this information could be requested. • The team considered adding a new subpart at the end of Requirement 1 (e.g., 1.6), but after reviewing Requirement language, the team determined the data and information lists within the existing subparts were the appropriate place to capture IBR-specific modeling data and parameters. MOD-032: • Generator Owner and Generator Operator – The DT decided to put the responsibility on just the Generator Owner and did not add Generator Operator as a functional entity to the applicability section. If data is needed from the Generator Operator, then the Generator Owner can reach out to the Generator Operator for necessary data via contractual obligations, etc. The team does

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Directive Language	**Standards Impacted**	**Consideration of Directives**
		not find it necessary to require two applicable entities when one oversees the other. • The team modified attachment 1 to include Generation and storage units, removed photovoltaic system (covered within IBR) and added Inverter-Based Resources. The wind turbine was updated for clarity that it is for Type 1 and Type 2.
P77. "With regard to AEU and ACP/SEIA's comments that the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners and operators, we believe that this request may already be addressed through each transmission planner's existing processes. For example, the New York Independent System Operator (NYISO) and CAISO both have processes for obtaining such data after demonstrating a need for the specific information requested and that the required information protection and non-disclosure agreements are signed. Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." **P74.** "AEU and ACP/SEIA ask that, in addition to data provision requirements for generator owners and operators, the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners. For example, AEU explains that	MOD-032	**Theme:** Information going from Transmission Owner to Generator Owner/Generator Operator (consider): MOD-032 • There is no specific requirement within MOD-032 that requires Transmission Owners to share data with the Generator Owners and Generator Operators. However, Transmission Planners and Planning coordinators have a framework where requests for data can be sent for inclusion for the interconnection-wide models. At this time, the team does not see a need for a requirement to be drafted requiring Transmission Owners to provide data to Generator Owners and Generator operators. The team believes this is most appropriately addressed through processes that exist outside of NERC reliability standards and concurs with the suggestion in P77 that these processes are already in place.

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Directive Language	**Standards Impacted**	**Consideration of Directives**
generator owners and operators also require data from transmission owners to support accurate modeling and performance, e.g., short circuit data, grid data for offshore wind, information on other power electronic devices around the IBR plant, and voltage harmonics. AEU adds that putting requirements on transmission owners would be consistent with revisions being developed for NERC's Modeling, Data, and Analysis (MOD) Reliability Standards."		
P78. "Commenters raised general concerns that mandating specific modeling and data submissions would reduce the flexibility and discretion of transmission planners and operators to identify the information they need. We find that, given the need for IBRs to operate in a predictable and reliable manner to ensure the reliable operation of the Bulk-Power System, it is necessary to establish uniform, minimum categories or types of data that must be provided so that Bulk-Power System planners and operators can predict the behavior of all IBRs. As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions."	MOD-032 TOP-003 IRO-010	**Theme:** Individual use of approved IBR models. (ERO Approved Criteria for Acceptable Models) **Applicability:** Transmission Planner and Transmission Operator MOD-032 • An ERO Approved Criteria for Acceptable Models document has been developed. The Criteria for Acceptable Models defines the minimum criteria for model usability and quality for model submissions under the MOD-032, TOP-003, and IRO-010 Reliability Standards, as well as other Reliability Standards that may be revised from time to time to incorporate these Criteria. • IBR has been included in Attachment 1 of MOD-032 under steady state (item 3), dynamics (item 7), and short circuit ensuring that entities are clear that IBR needs to be addressed as required per FERC Order 901. • IBR was added to the TOP and IRO standards to clarify obligations when this specific data is requested.

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P86. "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."**	TOP-003 IRO-010	**Theme:** Disturbance and monitoring (Consider) (real-time operations) **Applicability:** Generator Owner TOP-003/IRO-010 • TOP-003 and IRO-010 Reliability Standards are already structured in an open way so that any type of data needed can be requested at any time. In addition, transmission of information from the plant level is generally dealt with via interconnection agreements and does not rise to the level of a requirement being needed at this time. Lastly, PRC-028 PMU devices must be installed for every IBR installation. These additional monitoring devices will allow additional data requests related to those devices if the applicable entities would find that useful.
P102. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal, with modification. Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System	MOD-032 IRO-010 TOP-003	**Theme:** 1) TO provide data for unregistered IBR and 2) DPs provided data for IBR-DER **Applicability:** Transmission Owner and Distribution Provider • The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1. After a good bit of discussion, it was determined to add that the respective functional entity can estimate, should there be limitations of availability of data. In addition, the DT did not know how to interpret material affect and therefore, left it up to the Planning Coordinator and each of its Transmission Planners to review,

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planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System."		consider, and determine all unregistered IBR that would be material impacted. • The IRO-010 and TOP-003 language already there to address the IBRs.
P104. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) Estimation, if not able to get data from unregistered IBRs, 2) an explanation of the limitations of the availability of data, 3) explanation of the limitations of any data provided by unregistered IBRs, and 4) method for estimation. (directive) **Theme 2:** Implement a process or mechanism by which Transmission Owners would receive modeling data and parameters. (consider) **Applicability:** TO • The DT added a Requirement R2 Part 2.1 allowing the functional entity to use the method of estimation should it find itself in a place unable to gather unregistered IBR data or DER data. However, it must include an explanation of the limitations of the availability of data, an explanation of the limitations of any data provided for unregistered IBRs or DERs, and the method used for estimation. • The DT discussed implementing a process or mechanism by which Transmission Owners would receive modeling data and parameters in depth. It was determined that if an entity is unable to gather data from unregistered IBRs, then it is better to leave open for Transmission Owner and Distribution Provider to acquire data how they see fit. This is something that entities can determine in the planning process.

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estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the reliability of the Bulk-Power System. To support this data collection, we further direct **NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."**		• IRO-010 and TOP-003 language already there to address the IBRs.
P105. "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. (Directive) **Theme 2:** consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters. (Consider) **Applicability:** Distribution Provider The DT added a new Requirement R2 Part 2.1 that if the responsible entity is unable to gather unregistered IBR data or DER data and provide it to the Transmission Planner and Planning Coordinator, as specified in the data requirements and reporting procedures developed under Requirement R1, the responsible entity shall provide an estimate of the modeling data and parameters and include an explanation of the limitations of the availability of data, an explanation of the limitations of any data provided for unregistered IBRs or DERs, and the method used for estimation.

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implement a process or mechanism by which distribution providers would receive modeling data and parameters."		The DT discussed the possible mechanism by which Distribution Providers would receive modeling data and parameters. The team did not feel this rose to the level of a requirement as the Distribution Provider can ask for the modeling data and parameters from the respective entity.
P106. "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."	MOD-032 IRO-010 TOP-003	**Theme:** Who is the responsibility entity when no registered DP of IBR-DER (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation. • Upon a decent amount of conversation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote stating: "The DP is the typical responsible entity for collecting and providing data for DER connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the DP's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the TO's system."
P108. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request that the final rule specify the data to be submitted by	MOD-032 IRO-010 TOP-003	**Theme:** minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers that are necessary to predict the behavior of all

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all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear. As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions. By contrast, we believe that a directive to task distribution providers as the appropriate registered entity to collect and share the modeling data and parameters of IBR-DERs in the aggregate is preferable to deferring to the stakeholder process as suggested by APS. The distribution provider, as the entity providing and operating the lines between the transmission and distribution systems, is the entity best situated to have access to the data necessary for accurate estimation and, other than Indicated Trade Associations that suggested the piecemeal approach already discussed above, no commenter identified other potential entities as an equally efficient option."		IBRs and to ensure that compliance obligations are clear (ERO Approved Acceptable Criteria for Models/IEEE1547 ref./modify req./Tech rationale) **Applicability:** Transmission Planners, Transmission Operators, Transmission Owners, and Distribution Providers • The ERO Approved Criteria for Acceptable Models ensures that acceptable behavior is being considered for all types of IBRs, and added Requirement R2 Part 2.1 ensures entities have a way to address unregistered IBR and IBR-DER data if it is not available. In addition, the ERO Approved Criteria section from the ERO Approved Criteria for Acceptable Models requires planning models, operational models, and usability requirements demonstrate disturbance behavior of all IBRs during steady state, short-circuit, and dynamic conditions.
P122. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require the	MOD-032 IRO-010 TOP-003	**Theme**: require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-

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use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."		circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. The Criteria for Acceptable Models defines the minimum criteria for model usability and quality for model submissions under the MOD-032, TOP-003, and IRO-010 Reliability Standards, as well as other Reliability Standards that may be revised from time to time to incorporate these Criteria. The applicable standards connect the ERO Approved Criteria for Acceptable Models via requirements language added in each standard. In addition, IBRs have been added to Attachment 1 ensuring this is captured in steady state, short-circuit, and dynamic conditions.
P124. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies. We acknowledge NERC's comment that user-defined models may be helpful for specific local reliability studies; however, the user-defined model cannot be used in place of nation-wide approved component models for regional analysis or interconnection-wide analysis because the user-defined model may cause non-convergence and other issues. However, NERC may allow the submission of user-defined models alongside the approved industry generic IBR model. Various entities do not accept user-defined models or only accept them for limited		**Theme:** nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies. (ERO Approved Criteria for Acceptable Models) The ERO Approved Criteria for Acceptable Models will focus on the use and representation of positive sequence phasor domain (PSPD) models in registered entity footprints and in Interconnection-wide models. Interconnection-wide modeling may be different from the models used in specialized studies dedicated to a particular technical objective. NERC's Criteria for Acceptable Models applies to the models where NERC Reliability Standards require its use (generally for planning and operation models where multiple entities share information beyond their portion of the electric system, which includes Interconnection-wide models). Further guidance for

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instances along with the open-source code which then allows internal model components to be viewed and modified. For example, PJM does not accept user-defined models and requires generic models for model verification in accordance with currently effective Reliability Standards MOD-026-1 and MOD-027-1. NYISO accepts a user-defined model in limited instances but requires either the open-source code (allowing anyone to access the internal model) or dynamic link library data and code files (compiled code that must be decompiled to view the internal model) that must be supplied for existing power flow software and in perpetuity."		interconnection applications can be found in the *NERC Dynamic Model Recommendations*.
P125. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models. One example of a way NERC could meet this directive would be to require an equivalent generic library model along with all submissions of user-defined models so that the generic library model can be used when combining neighboring transmission system models and in interconnection-wide models."	MDO-032 IRO-010 TOP-003	**Theme:** nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models. (ERO Approved Criteria for Acceptable Models/Req language) • Nation-wide approved components via generic library models are addressed via the development of the ERO Approved Criteria for Acceptable Models and the addition of a Requirement Part has been added to MOD-032, TOP-003, and IRO-010. • If an entity wants to provide a generic model library, they are allowed to do so, but if equipment-specific models satisfy usability criteria, they are not prohibited.
P141. "We also direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g.,	MOD-032 IRO-010 TOP-003	Repeat of above. **Applicability**: GO

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior. Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives. Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements		• Nation-wide approved components via generic library models are addressed via the development of the ERO Approved Criteria for Acceptable Models and the addition of a Requirement Part has been added to MOD-032, TOP-003, and IRO-010. This approach is aligned with the FERC Order directives while addressing the practical limitations raised by industry at January 15-16 NERC Industry Engagement Workshop • MOD-032, Attachment 1 was modified to specifically add that capabilities related to momentary cessation, tripping, and Ride-through, be reflected in the required model data for IBR and DER.

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
performance to represent different steady-state and dynamic behavior). Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives. Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models. Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that		

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
in the aggregate have a material impact on the Bulk-Power System."		
P146. Accordingly, **we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to be able to perform respective system studies. For example, the new or modified Reliability Standards could require models of IBR-DERs (i.e., DER_A model) to adequately reflect the steady-state and dynamic aggregate** resource performance in both a transmission area and across the interconnection. Additionally, estimated modeling data and parameters of IBR-DERs that in the aggregate (i.e., DER_A model) have a material impact on the Bulk-Power System could be used where measured and collected data is not available. We believe requiring the DER_A model will address NERC's request for entities to work collaboratively with the state regulators to identify, implement, and perform an effective model validation approach for IBR-DERs in the aggregate as opposed to requiring validated models of IBR-DER in the aggregate that can have a material impact on the reliable operation of the Bulk-Power System.	MOD-032 IRO-010 TOP-003	**Theme**: IBR-DER Model • The ERO Approved Criteria for Acceptable Models document requires models that are appropriate for the intended use and meet usability criteria. The currently available DER_A model is sufficient only for positive sequence phasor domain simulations. With the variety of other simulation domains necessary to study IBRs, mandating this model could prevent TPs or PCs performing their studies. This further reinforces the team's election to not require the use of the DER_A model, but rather a model that achieves specific performance criteria and conforms with MOD-032 edits in Attachment 1 and R1. • The team considered referencing the DER_A model specifically, but refrained due to the rapidly evolving nature of models and concerns for the time required to update such a reference in a NERC Standard. Further, challenges with precisely defining and determining what a "successor model" is could potentially create more future reliability risks.
P157. We believe the development of new or modified Reliability Standards is an important corollary to NERC's	MOD-032 TOP-003	**Theme:** Who is the responsible entity when no registered DP of IBR-DER. Framework aspect.

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
ongoing effort to identify and register generator owners and operators of IBRs. Although NERC's registration changes will not at this time address IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, we believe APS's concerns regarding system-wide model validation is addressed in NERC's Reliability Guidelines and through the use of the EPRI DER Settings Database. We recognize that some distribution providers may not be able to provide a precise set of modeling data and parameters that accurately represent IBR-DERs in the aggregate. For these situations, NERC has provided a technical means to estimate in aggregating the needed IBR-DER modeling data and parameters (i.e., for the DER_A model) in the IBR-DER Data Collection Guideline. Further, NERC's 2021 Aggregate DER Model Verification Guideline provides transmission planners and planning coordinators with tools and techniques that can be adapted for their specific systems to verify that aggregate DER models (i.e., DER_A models) are a suitable representation of these resources in planning assessments. **Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to establish a process that**	IRO-010	Upon a decent amount of conversation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote stating: "The DP is the typical responsible entity for collecting and providing data for DER connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the DP's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the TO's system."

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
requires identified registered entities to coordinate, validate, and keep up to date the system models.		
P161. "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal to provide additional specificity to explain coordination and keep up to date in a timely manner the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate in the system models. **Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model.** Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these	MOD-032 IRO-010 TOP-003	The DT modified MOD-032 to ensure it captures the uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange has been modified via TOP-003 and IRO-010.

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
resources in the system models. For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives. NERC may implement this directive by modifying Reliability Standards MOD-032-1 and MOD-033-2 or by developing new Reliability Standards to establish requirements mandating an annual process to coordinate, validate, and keep up-to-date the transmission planning, operations, and interconnection-wide models."		
P226. "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	MOD-032 IRO-010 TOP-003	**Theme:** sufficient timeframe. The DT felt that four years was an appropriate timeframe for the MOD-032, IRO-010, and TOP-003 standards. However, taking into consideration an implementation plan completion of 2030 per FERC Order 901 required the team to go back to the table and re-think the timeframe knowing that milestone 4 still needs to be completed and allowed implementation plan time. It is understood that based on what is being required via MOD-032, industry would need at least one year to gather data, hold meetings with respective OEM or developers to gather models needed, and then an additional two years to update models based on the ERO Approved Criteria for Acceptable Models document, etc. The team settled on three years implementation plan for MOD-032 and then synced up TOP-003 and IRO-010 with three years

FERC Order 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
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 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."		implementation plan for the respective functional entities to provide data upon requests.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Approved Criteria for Acceptable Models

Project 2022-02 Uniform Modeling Framework for IBR

April 2025

RELIABILITY | RESILIENCE | SECURITY






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Executive Summary

The Criteria for Acceptable Models defines criteria for model submissions under the MOD-032, TOP-003, and IRO-010 Reliability Standards. Models that are submitted for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system shall meet requirements in this document.

Disclaimers

Interconnection-wide modeling requirements may differ from the requirements of specialized studies dedicated to a particular technical objective. NERC's Criteria for Acceptable Models applies to the models where NERC Reliability Standards require its use (generally for planning and operation models where multiple entities share information beyond their portion of the electric System, which includes interconnection-wide models).

Operations models shall meet the requirements in this document, provided that models for operations shall not reduce the ability of a Registered Entity to perform their Operational Planning Analyses and Real-Time Assessments (RTAs) in a timely manner. Thus, models deemed acceptable for planning purposes may be deemed unacceptable by a receiving entity for certain operations applications.

Chapter 1: Process

Updates to the Criteria for Acceptable Models

This section describes the process by which changes may be made to the Criteria for Acceptable Models or the revision processes in this document, excluding changes to the Unacceptable Models List which will be addressed in the following section.

1) Any person or entity may submit a request to the ERO to revise the Criteria for Acceptable Models. This request shall include, at a minimum:
   a. Description of the suggested revision;
   b. Technical justification for the suggested revision;
   c. Supporting documentation; and
   d. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure.
2) ERO staff shall review and evaluate the Criteria for Acceptable Models revision request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee (RSTC) or its successor charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3) As part of the review process, ERO staff shall conduct a 45-day public comment period on the proposed revision request.
4) The proposed revision request, along with the results of the review, the comments received, a summary consideration of comments, and the recommended action, shall be presented to the NERC RSTC or its successor in a duly noticed public meeting.
5) The NERC RSTC may recommend the NERC Board of Trustees approve the revision request, reject the revision request, or remand the revision request for further work. If the NERC RSTC recommends approving the revision request, the NERC RSTC shall also recommend an effective date for the revision.
6) The NERC Board of Trustees, considering the recommendation of the NERC RSTC, shall approve the revision request, reject the revision request, or approve the revision request with modifications. If approved, the NERC Board of Trustees shall also approve an effective date for the revision.
7) The ERO shall provide public notice of a revision to the Criteria for Acceptable Models along with the effective date of the revision. The revised Criteria for Acceptable Models shall be posted to the NERC website and filed with FERC for informational purposes.

Updates to the Unacceptable Models List

This section describes the process by which changes may be made to the Unacceptable Models List. The following steps shall be taken to add, remove, or modify a model to the Unacceptable Models List:

1) Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
   a. The model name;

b. Alternative model name(s), if any;

c. Organization(s) the submitting entity represents;

d. Description of the model's stated intent;

e. Request to add model as an "unacceptable" model or remove model as an "unacceptable" model;

f. Technical supporting documentation that includes the ability of the model to meet or not meet small and large disturbance behavior;

g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and

h. An explanation, if any of the above technical support items are unavailable to the supporting entity.

2) ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC RSTC or its successor charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.

3) If the request is seeking to add a model to the Unacceptable Models List, ERO staff shall provide public notice that identifies the model being considered for addition to the list, includes a non-confidential summary of the rationale offered for its inclusion, and provides at least 30 days to submit comments.

4) The results of this review and the recommended action shall be presented to the NERC RSTC or its successor in a duly noticed public meeting.

5) The NERC RSTC may recommend the NERC Vice President of Engineering and Standards[1] approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving the change request, the NERC RSTC shall also recommend an effective date for the change.

6) The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.

7) The ERO shall provide public notice of a change to the Unacceptable Models List included in this Approved Criteria for Acceptable Models along with the effective date of the change. The revised document shall be posted to the NERC website and filed with FERC for informational purposes.

8) Technical Rationale for each model added to the Unacceptable Models List shall be retained by the ERO for as long as practicable, but no fewer than five (5) years from the date a model is added to the list.

[1] This may include an equivalent NERC officer if by a different title, or their designee.

Chapter 2: ERO Approved Criteria

Planning Models

Models that are submitted for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system shall qualify with the following:

1) All models shall be representative of expected or as-built facilities.
2) All models shall be usable (see usability requirements below).
3) All standard library models are deemed acceptable until demonstrated to not meet usability requirements and/or demonstrated to be unable to represent the expected or as-built facilities.[2]
4) Models listed on the Unacceptable Model List shall not be used unless it is demonstrated that such a model represents the expected or as-built facilities with negligible error(s) in both small signal and large disturbance behavior and does not introduce numerical instability in the software used by TPs or PCs. In these cases, the model submitting entity may submit a request to update the Unacceptable Model List. A model may be used pending the disposition of the request.

Operational Models

Models that are submitted for development of operation cases necessary to support analysis of the reliability of the interconnected transmission system shall qualify with the following:

1) All models shall be representative of expected or as-built facilities.
2) All models shall be usable (see usability requirements below).
3) All standard library models are deemed acceptable until demonstrated to not meet usability requirements and/or demonstrated to be unable to represent the expected or as-built facilities.[3]
4) Models listed on the Unacceptable Model List shall not be used unless it is demonstrated that such a model represents the expected or as-built facilities with negligible error(s) in both small signal and large disturbance behavior and does not introduce numerical instability in the software used by TPs or PCs. In these cases, the model submitting entity may submit a request to update the Unacceptable Model List. A model may be used pending the disposition of the request.
5) Models shall not reduce the viability of a Registered Entity's ability to perform their OPAs and RTAs in a timely manner.

Usability Requirements

Models that are used for representation of generation and system components shall have sufficient documentation for the user of the model to understand its parameters, states, and outputs into the simulation software. Usable models are those models that include, at a minimum, the following:

1) A model manual, or other documentation, with a description of all model parameters, variables, and states. The manual or other documentation shall also describe the range of validity of the model and valid use cases or studies for which the model has sufficient fidelity.
2) A procedure to use and initialize the model in dynamic simulations, including alterations to the steady-state representation.

[2] Poor model quality may stem from poor parameterization and/or poor implementation of a model from code. Poor parameterization or poor implementation of a particular model shall not be used to generalize a model's designation in the Unacceptable Model List.

[3] Poor model quality may stem from poor parameterization and/or poor implementation of a model from code. Poor parameterization or poor implementation of a particular model shall not be used to generalize a model's designation in the Unacceptable Model List.

3) Disclaimer(s) on the usability of the model for known model software or simulation domains.
4) An explanation of the model's adequacy to represent small and large disturbance behavior.
5) A list of commonly tuned parameters to align the model to site-specific settings as well as allowable tuning ranges for these parameters.

Chapter 3: Unacceptable Models List

Models that have been identified as unacceptable as list in Table 1 below. Revisions to this list may be made in accordance with the process described in "Updates to the Unacceptable Models List" above.

Table 1: Unacceptable Model List	
Known Unacceptable Model Name	**Model Description**
Renewable Energy Models	
WT3G1, WT3G2, wt3g	Generic Type 3 WTG Generator/Converter Model - Doubly-fed induction generator
WT4G1, WT4G2, wt4g	Generic Type 4 WTG Generator/Converter Model - Variable speed generator with full converter
WT3E1, wt3e	Generic Type 3 WTG Electrical Control Model
WT4E1, WT4E2, wt4e	Generic Type 4 WTG Electrical Control Model
WT3T1, wt3t	Generic Type 3 WTG Turbine Model
WT3P1, wt3p	Generic Type 3 WTG Pitch Control Model
WT12A1, wt1p, wt2p	Generic Type 1 and 2 WTG Pitch Control Model
WT4E1, wt4t	Generic Type 4 WTG Power Converter Model
wt4p	Generic Type 4 Pitch Control Model
REECB1, REECBU1, reec_b	Generic Phase 2 PV Electrical Controls Model
Machine Models	
GENSAL, gensal	Salient Pole Generator Model (IEEE Std 1110 §5.3.1 Model 2.1)
GENCLS, gencls	Classical Generator Model (IEEE Std 1110 §5.4.2)
GENTRA	Transient Level Generator Model
Excitation System Models	
texs	General Purpose Transformer Fed Excitation System
SEXS, sexs	Simplified Excitation System
EX2000	GE EX2000 Excitation System
Turbine-Governor Models	
lm2500	LM 2500 Aero-Derivative Gas Turbine Governor Model
lm6000	LM 6000 Aero-Derivative Gas Turbine Governor Model
URGS3T, gast	WECC Gas Turbine Governor Model
GAST	Gas Turbine-Governor Model
GAST2A	Gas Turbine-Governor Model
GASTWD	Gas turbine-governor
IEEEG2	1981 IEEE Type 2 General Approx. Linear Ideal Hydro Model
WESGOV	Westinghouse Digital Governor Model for Gas Turbines
Load Models	
motorc	Phasor Model of Single-Phase Air-Conditioner Compressor Motor

Chapter 4: Form Revisions

This form is a sample to explain what is deemed a full application to change a model designation in the NERC Approved Model Criteria for Acceptable Models List.

Name of Person submitting			
Organization(s):			
Sector (if known)			
Telephone		Email	

Model Name	
Alternative Model Name(s) as implemented in software	
Equipment Model is stated to represent	
Indicate desired Action	☐ Add "model to the Unacceptable Models List, Section X of the Approved Model Criteria for Acceptable Models ☐ Remove model from the Unacceptable Models List, Section X of the Approved Model Criteria for Acceptable Models

Description of model ability to meet small signal Disturbances	
Description of model ability to meet large signal Disturbances	
Please cite and link any industry approved documentation regarding this model's small and large signal disturbances	
Describe the technical document attachments that support the above questions	
Please identify any information in this application that may meet the criteria for Confidential Information, as defined in Section 1500 of the NERC Rules of Procedure.	

Section 4: Process Tracking	
Date Submitted to ERO	
Model Status	☐ Submitted to the ERO ☐ Assigned ERO Review team ☐ Investigation and review by ERO and submitting entity ☐ Remanded by NERC RSTC (or its successor) ☐ Approved by the NERC RSTC (or its successor)
Date of Approval	
Date of Model Notice to Industry	

Attachments:

If available, please include at least one report that demonstrates the ability or inability of the model to meet its stated purpose using Hardware-in-the-Loop, Software-in-the-Loop, or actual System response (e.g., in a commissioning test) that demonstrates the ability or inability to meet the model's stated purpose. At least one attachment should detail the model's error boundaries to represent its stated equipment with the test description and procedure outlined in that report. Entities shall label any attachment that may meet the criteria for Confidential Information under NERC Rules of Procedure Section 1500, along with the basis for the designation (e.g., Confidential Business and Market Information, Critical Electric Infrastructure Information, etc.). If any of this information is not available to the supporting entity, please provide an explanation.

Chapter 5: Technical Rationale

FERC Order No. 901

This document addresses directives within Federal Energy Regulatory Commission (FERC) Order No. 901 outlining the need to use industry approved models. Pre-defining a limited set of models (i.e., a library of models) that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. Thus, instead of specifying a limited model library, this document provides acceptability criteria for models representing generation and system components. This document is based on the *NERC Dynamic Modeling Recommendations*[4] but is standalone. Entities are encouraged to review the *NERC Dynamic Modeling Recommendations* for further consideration and technical background for this Criteria for Acceptable Models.

Operational Models

Transmission Operators (TOPs), Reliability Coordinators (RCs), and Balancing Authorities (BAs) are required to have a "documented specification for the data necessary" to perform Operational Planning Analysis (OPA), Real-Time Assessment (RTA), and Real-time Monitoring. This data specification is then distributed by the TOP, RC, and BA to entities to fulfil the data requirements and such entities provide the data in mutually agreeable format, security protocol, and process for resolving data conflicts. FERC Order No. 901 has identified that the transient dynamic performance of Inverter-based Resources (IBRs) is underrepresented in these models. However, many OPAs and RTAs do not perform a transient dynamic simulation for all credible Contingencies due to computational time constraints. As such, models for operations shall meet the same criteria for models for planning. Thus, models deemed acceptable for planning purposes may be deemed unacceptable by a receiving entity for certain operations applications.

Unacceptable Model List

As models have evolved and been implemented in software, some models have been proven to contain modeling errors, numerical issues, insufficient technical documentation, or have been phased out of use by the owners of the equipment due to the availability of better models. The unacceptable list of models shown in Table 1 below is categorized by the type of model, and as of publication, includes only PSPD models. Revisions to this list may be made in accordance with the process described in the "Updates to the Unacceptable Models List" above.

Usability Requirements

In current planning model software, most standard library models come with a list of parameters, their description, initial values, and the appropriate disclaimers. In these cases, references to the program's application manual suffices for usability requirements 1 through 3.

In addition to the content usability requirements above, any identified inability of a model to function properly within a System Model may cause a model to be deemed unacceptable until the issue is addressed and eliminated. Such software usability issues include, but are not limited to:

1) Models that restrict user selection of the machine unique identifiers (e.g., number, name, ID) beyond the inherent software limitations.
2) Models that fail to robustly initialize under reasonable initial conditions.
3) Models that cause simulation crashes or conflict with other models in a system simulation, including other instances of the same model.
4) Models that require unique folder structures that are incompatible with System Model development.
5) Models that cause numerical instability or simulation solution challenges.

[4] Available here: https://www.nerc.com/pa/RAPA/ModelAssessment/Documents/Dynamic%20Modeling%20Recommendations.pdf

Criteria Checklist Guideline

If all the checkboxes below can be attested to with evidence that the model meets these criteria, then the model at the date of delivery is deemed acceptable in accordance with this ERO Approved Criteria for Acceptable Models.

- ☐ The model name and description is not listed in the Unacceptable Model portion of the ERO Approved Criteria for Acceptable Models.
- ☐ The model is accompanied by a manual with descriptions of all model parameters, variables, and states.
- ☐ The model manual describes the range of validity of the model and valid use cases or studies for which the model has sufficient fidelity.
- ☐ The model is accompanied by a list of commonly tuned parameters for site-specific settings.
- ☐ The model is accompanied by a procedure to use and initialize the model in dynamic simulation.
- ☐ The model accompanied by an explanation of the model's adequacy to meet small and large disturbance behavior.
- ☐ The model does not place restrictions on unique identifiers (e.g., number, name, ID) used in simulation software.
- ☐ The model initializes robustly for all reasonable initial conditions and does not cause simulation crashes.
- ☐ The model does not require unique and burdensome folder structures that are incompatible with System Model development.
- ☐ The model does not cause numerical instability or simulation solution challenges.

Chapter 6: Version History

Version	Date	Action	Change Tracking
1	April 2025	Draft 1 Posting for Project 2022-02	Initial Draft

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Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Formal Comment Period Open through May 16, 2025
Ballot Pools Forming April 17 – 28, 2025

Now Available

A formal comment period for **Project 2022-02 Uniform Modeling Framework for IBR**, is open through **8 p.m. Eastern, May 16, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- 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, Monday, April 28, 2025.** 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 standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **May 7 – 16, 2025**.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 470-479-7538. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR observer list” in the Description Box.

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Comment Report

Project Name:	2022-02 Uniform Modeling Framework for IBR | Draft 1
Comment Period Start Date:	4/17/2025
Comment Period End Date:	5/16/2025
Associated Ballots:	2022-02 Uniform Modeling Framework for IBR | Draft 1 Implementation Plan IN 1 OT 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 | Non-binding Poll IN 1 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 IN 1 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 | Non-binding Poll IN 1 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 IN 1 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 | Non-binding Poll IN 1 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 IN 1 ST

There were 82 sets of responses, including comments from approximately 174 different people from approximately 105 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed MOD-032-2 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

2. Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system? If not, what entity would be in a better position to provide that data and add justification?

3. Do you agree with the proposed IRO-010-5 and TOP-003-8 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

4. Do you agree with the proposed DER definition? Please refer to the technical rationale, which provides rationale behind the drafting team's intent and previous definitions proposed. If you do not support the definition as proposed, please explain the changes that, if made, would result in your support.

5. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-5, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

6. Do you agree with the proposed ERO Approved Criteria for Acceptable Models document? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

7. Provide any additional comments for the 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		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
Santee Cooper	Chris Wagner	1		Santee Cooper	Weijian Cong	Santee Cooper	1,3,5,6	SERC
					Chris Wagner	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group, Inc.	3	RF
					Michelle Hribar	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
					Candace Morakinyo	WEC Energy Group, Inc.	4	RF
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC

					Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
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,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	James Shultz	Hoosier Energy Electric Cooperative	1	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF

					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
Black Hills Corporation	Josh Schumacher	6		Black Hills Corporation Segments 1, 3, 5, 6	Trevor Rombough	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
					Josh Schumacher	Black Hills Corporation	6	WECC
Midcontinent ISO, Inc.	Kirsten Rowley	2		ISO/RTO Council (IRC) Standards Review Committee (SRC)	Elizabeth Davis	PJM	2	RF
					Kirsten Rowley	Midcontinent ISO, Inc.	2	RF
					John Pearson	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Joshua Phillips	Southwest Power Pool, Inc. (RTO)	2	MRO
					Kennedy Meier	ERCOT	2	Texas RE
					Jamie Johnson	California ISO	2	WECC
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
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
Northeast Power Coordinating Council	Ruida Shu	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
					Salvatore Spagnolo	New York Power Authority	1	NPCC

Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	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
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
Emma Halilovic	Hydro One	1,3	NPCC
Philip Nichols	National Grid	1	NPCC
Emma Halilovic	Hydro One	1,3	NPCC
Caver Powers	Utility Services	5	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
Dominion - Dominion Virginia Power	Victoria Crider	3		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable

1. Do you agree with the proposed MOD-032-2 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA does not support the proposed revisions in MOD-032-2, specifically, R2.1. BPA believes the TO is not the appropriate registered entity to be responsible for providing estimations of unregistered load. BPA has 133 load modeling entities within its footprint, with a combined winter peak load of 12.2 GW. 110 of these entities are unregistered, which accounts for 6.4 GW of the total load.

BPA, as a TO, does not have visibility into an unregistered entity's systems to provide an estimate of the data at any level of accuracy. BPA believes an uninformed estimate could negatively impact system reliability. BPA advocates that the best way to close the data gap is to close the registration gap. BPA recommends unregistered DPs become registered if only to supply IBR and DER data. BPA suggests a new compliance registry "DP-DER" registration.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy asks for clarification on the following:
Footnote 1 states:
As used in this standard, the phrase "unregistered IBR" refers to a Bulk-Power System connected IBR that does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

Footnote 1 introduces the term "unregistered IBR" but does not adequately define it. Does the term "Unregistered IBR" only refer to IBRs that meet Category 2 criteria? This is not clear in the footnote as written.

Also, Project 2024-01 passed on May 7, 2025, which adds "Category 2" IBRs to the Generator Owner definition. Does that change the meaning of Footnote 1 since Generator Owner now includes both Categories 1 and 2? Would this change the meaning of the footnote 1 to include unregistered IBRs not already applicable under Categories 1 and 2?

In addition, FirstEnergy supports EEI's comments which state:

EEI does not agree that enforceable Reliability Standards should be reliant on external documents such as the document titled "ERO Approved Criteria for Acceptable Models" (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. Moreover, the

Commission did not direct NERC to develop such a document but instead directed NERC "to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria" (emphasis added; FERC Order 901, P161).). To better align with FERC Order 901, we offer the following comments and suggested edits in boldface below:

Requirement R1

EEI does not support maintaining model criteria within ERO document titled ERO Approved Criteria for Acceptable Models for the reasons detailed in our response to Question 6 below. To address this concern, we offer the following modifications to requirement R1 below, which we believe would satisfy FERC Order 901 directives, place the criteria back within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection. These edits are limited to part 1.2 in boldface below:

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1 The data listed in Attachment 1, including the responsible entity for each required item.

1.2 Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization (ERO) Specifications for the following items for dynamic models submitted in accordance with Attachment 1:

1.2.1 A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.2.2 Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s), or a technical justification for the submission and use of user-written models if such models are permitted.

1.2.3 Criteria for any submitted user-written models including, at a minimum, documentation, and performance criteria to minimize the risk of non-convergence and other issues. The PC's user-written model criteria must be made available to all other TP/PC's within the Interconnection for review and comment, and approval where the usage of the user-written model represents a shared impact.

1.3 Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.3.1 Data format;

1.3.2 Level of detail to which equipment shall be modeled;

1.3.3 Case types or scenarios to be modeled; and

1.3.4 A schedule for submission of data at least once every 13 calendar months.

1.4 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

Footnote 1: For example, the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases.

Requirement R2

EEI does not support Requirement R2, part 2.1 because this requirement places compliance obligations on the TO that they have no practical method of fulfilling without the support of the unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While it is unclear how DER data from unregistered entities might impact BPS reliability, TO will be limited in their ability to fulfill their compliance obligations without the direct assistance and participation for unregistered DPs. To address this concern, guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material

impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DPs. We additionally offer some suggested boldface edits to Requirement R2 to add additional clarity:

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1 For unregistered Inverter-based Resource (IBR) data, the responsible TO, whose transmission system these resources are connected, shall develop estimates of the aggregated unregistered IBRs including estimated modeling data. The TO shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations.

2.2 For Distributed Energy Resource (DER) data the responsible DP shall develop estimates of the aggregated DER connected to their distribution systems including aggregated modeling data. The DP shall also include an explanation of the limitations of the aggregated data as provided and the methods used for their estimations.

2.3 For distribution systems that are interconnected to a responsible TO system, where no registered DP exists, the TO shall document all attempts to gather aggregate estimates of DER capacity from the unregistered DP.

2.3.1 If the TO is success in gathering aggregate estimates of DER capacity from the unregistered DP, the data shall be forwarded to the responsible PC and TP so they can assess if the DER capacity on the unregistered DP's distribution system represents a material impact on the BPS.

2.3.1.1 If the PC & TP determines a material impact exists, their findings shall be reported to the ERO for further actions.

2.3.1.2 If the PC & TP determine there is not a material impact, no further actions are required by the responsible TO, unless further actions are requested by the PC & TP.

2.3.2 If the TO is unsuccessful in gathering aggregate estimates of DER capacity from the unregistered DP, they are to report their inability to collect the required data to both the responsible PC and TP, who will report the issue to NERC for further actions.

Attachment 1 Concerns: EEI offers the following comments and suggested edits (in boldface) to Attachment 1 below:

Item 2 – It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for in various modeling scenarios.

Item 9 – TOs are entirely dependent on responsible **registered** DPs and should therefore be removed from having direct responsibility for Aggregate DER data. Additionally, 9c should be edited (see boldface edit below) to better align with what DP are capable of collecting (i.e., aggregate DER data by storage types).

Dynamics Concerns

Item 5 - It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for various modeling scenarios.

Item 7 – Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR. To address our concerns, we offer the following boldface edits to Item 7:

7. Inverter-Based Resource **[GO, TO]**

a. Registered IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control **[GO]**

b. **Aggregated capability of non-registered IBRs connect to the BPS including estimates related to momentary cessation, tripping, Ride-through, and frequency control [TOs]**

Item 10 – TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed. To address our concerns, we offer the following boldface edits:

10. Aggregate Distributed Energy Resource (DER) data

a. **Estimates of aggregated** DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. **[DP, UFLS only DPs]**

b. **I**ndication whether DER**s is subject to tripping in conjunction with are part of any** UFLS or UVLS **schemes and provide estimates of the affected aggregated capacity on those schemes**. **[DP, UFLS only DPs]**

Footnote concerns

Footnote 1: EEI does not agree with Footnote 1. Data requirement obligations should be clearly specified within each sub-bullet of each column for both steady-state and dynamics to ensure responsible entities understand their roles.

Footnote 2: EEI suggests the following clarifying edits to footnote 2 in boldface:

For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. **A The** Distribution Provider is the **typical** responsible entity for providing this information, **generally** through coordination with the Transmission Owner.

Footnote 4: EEI does not agree that IBRs should be generically identified as storage devices. Instead, Battery Energy Storage System (BESS) should replace IBR in footnote 4. Note the following boldface edits:

This includes **IBR battery energy storage systems**, synchronous condensers, and pumped storage.

Footnote 5: Ambiguous terms like typical should not be included in NERC Reliability Standard. We additionally feel that it should be made clear the limits of TO responsibilities regarding unregistered IBRs.

The transmission owner is the **typical** responsible entity for collecting and providing **aggregate** data for unregistered IBRs that are not DERs **and directly connected to their portion of the BPS.**

Footnote 6: TO and DP have no ability to collect or provide aggregate data for DERs that are not connected directly to their system. If DER data is needed from unregistered DP to preserve the reliability of the BPS, then those entities should be registered. The following boldface edits have been provided to clarify what registered DP are capable of providing under MOD-032:

The Distribution Provider is the responsible entity for collecting and providing **aggregate** data for DER connected to **their distribution** system.

Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No

Document Name	
Comment	
AES adopts EEI's comments for MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Attachment One's 7a and 10a are both concerning. While there are provisions for representing voltage and frequency protection settings in positive sequence simulations, "momentary cessation, tripping, and ride-through" are too open-ended, may not be able to be represented completely in positive sequence phasor domain simulations, and lack the clarity needed to be certain of compliance. AEP suggests the following be used instead: 7a. "In the absence of project specific data, include estimated, assumed, or typical voltage and frequency protection settings." 10a. "Include estimated, assumed, or typical aggregate voltage and frequency protection settings." AEP recommends that a MW threshold level be established for requiring unregistered IBRs. AEP suggests 10 MW and above or as otherwise determined by the PC and TP in R1. In addition, there should also be a threshold level for requiring aggregate DER (affecting steady-state items 2 and 9, dynamics items 5 and 10) so as not to be found non-compliant for trivial amounts. AEP suggests 5 percent or greater of a TO's or DP's peak load or as determined by the PC and TP in R1.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	No
Document Name	
Comment	
Entergy has concerns about relying on "estimation of modeling data and parameters" required by R2.1 and introducing unverified DER model information into planning models and demonstrating compliance based on those estimations. **Footnote 3 in Attachment 1 – requires DPs make assumptions about generation output of behind the meter DER facilities to provide a gross demand number. Entergy proposes that R2.1 DER data be modeled as an aggregate MW generation as a percentage of the feeder, substation**	

transformer, or substation load. To optimize attaining meaningful results considering the proposed intense data demands set forth, Entergy recommends inclusion of a penetration threshold (ex: 20% of a substation gross load) for which these new modeling requirements become applicable.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA does not support the proposed revisions in MOD-032-2. Regarding R1.2, the ERO Criteria for Acceptable Models does not have industry consensus and was not established through the standards process. TVA does not believe it should be referenced in a compliance standard. In its place, TVA recommends specifications for standard models (where appropriate and available), user-written models (where appropriate and with adequate documentation), and other models (when no alternative is available and requiring justification for use). R2.1 asks entities that can't gather IBR/DER data to estimate the data. The model data that will be gathered with this provision is likely of low value and will potentially lead to more inaccurate models or models that have different issues. TVA does not believe the modeling responsibility for unregistered IBRs and aggregate DERs belongs with the TO and DP when that data, or lack there-of, must be estimated. Estimations of data without adequate information could negatively affect modeling. It is not uncommon for the TO and DP to lack visibility of unregistered IBRs and aggregate DERs. TVA recommends expanding the requirement to include “or justification on why unregistered IBR and/or aggregate DER was not modeled or estimated” to account for these circumstances. Regarding Attachment 1 Dynamics 10.b, this data could be difficult to accurately model for situations where the DP will often reconfigure their systems and move DERs between feeders. TVA recommends removing 10.b.	
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 review, and offers the following comments and suggestions.

Requirement R1 references the ERO-maintained Approved Criteria for Acceptable Models document. This document is not part of the Standard and may pose compliance challenges if updated outside of the Standard Development Process. The process to maintain the list of models (e.g. Unacceptable Model List) relies on NERC's determination on what would constitute an acceptable change implementation timeline, i.e. effective date.

For example, if the ERO added an existing data model to the List of Unacceptable Models in the ERO-maintained document without accounting for an adequate implementation timeline, entities may be in noncompliance on the effective date of the revised ERO document even though Standard had not been revised.

BC Hydro recommends that this document be included in the Standard, or otherwise provide for a change management process aligned with the Standard Development Procedures.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5

Answer	No
Document Name	

Comment

While the modifications are an improvement there are still areas that need to be addressed. For example, assigning the DP the burden to provide data on behalf of not registered DER's will add compliance obligations and will not provide the accurate data needed for an improved system model. A better approach is to provide a mechanism for the unregistered DER"s to become registered and therefore subjected to the same compliance obligations as registered DER's.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Under R1 the ERO-maintained Criteria for Acceptable Models is referenced. This document was not developed under the standard process and therefore does not have industry consensus. Tri-State is concerned that changes to this document outside of the standard could pose a potential problem.

Likes 0	

Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's comments regarding the modifications to MOD-032-2. The first issue of concern being the use of the external document "ERO Approved Criteria for Acceptable Models" to establish enforceable compliance requirements. We agree with EEI's suggestion that this be put back into the standard itself as part of Attachment 1. Black Hills Corporation also agrees with the EEI's conclusion that Section R2 places inappropriate burdens on the TO to gather information on installations they may have had no part in interconnecting and have no ability to compel those entities to provide information. We agree with their modifications to this section as well as attachment 1 that clarify which entities should typically be responsible for collecting data on these devices.	
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 EEI.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Reclamation does not agree with the addition of requirement 2.1. Unregistered entities do not fall under the purview of this standard or NERC requirements.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

Nextera supports comments provided by EEI

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

(1) The proposed MOD-032-2 modifications do not to address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models that accurately reflect the behavior of all IBRs).

(2) The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. There is disagreement regarding the enforceability of footnotes, which may leave certain entities vulnerable.

(3) P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.

Likes 0	
Dislikes 0	

Response

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI and MRO’s NERC Standards Review Forum’s (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	

Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	No
Document Name	
Comment	

We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.

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 its members:

Requirement 2

EEI does not support Requirement R2, Part 2.1 because this requirement places inappropriate compliance burdens on the TO that they have no practical method of fulfilling without the support of unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While EEI does not dispute that information from these unregistered entities may be needed and could impact BPS reliability, we do not agree that the answer is to place this compliance burden on TOs. Guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DPs. We additionally offer some suggested changes (clean version) to Requirement R2 to add additional clarity:

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1 For unregistered Inverter-based Resource (IBR) data, the responsible TO, whose transmission system these resources are connected, shall develop estimates of the aggregated unregistered IBRs including estimated modeling data. The TO shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations.

2.2 For Distributed Energy Resource (DER) data the responsible DP shall develop estimates of the aggregated DER connected to their distribution systems including aggregated modeling data. The DP shall also include an explanation of the limitations of the aggregated data as provided and the methods used for their estimations.

2.3 For distribution systems that are interconnected to a responsible TO system, where no registered DP exists, the TO shall document all attempts to gather aggregate estimates of DER capacity from the unregistered DP.

2.3.1 If the TO is success in gathering aggregate estimates of DER capacity from the unregistered DP, the data shall be forwarded to the responsible PC and TP so they can assess if the DER capacity on the unregistered DP's distribution system represents a material impact on the BPS.

2.3.1.1 If the PC & TP determines a material impact exists, their findings shall be reported to the ERO for further actions.

2.3.1.2 If the PC & TP determine there is not a material impact, no further actions are required by the responsible TO, unless further actions are requested by the PC & TP.

2.3.2 If the TO is unsuccessful in gathering aggregate estimates of DER capacity from the unregistered DP, they are to report their inability to collect the required data to both the responsible PC and TP, who will report the issue to NERC for further actions.

Attachment 1 Concerns:

EEI offers the following comments and edits (clean version) to Attachment 1 below:

Item 2 – It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for in various modeling scenarios.

Item 9 – TOs are entirely dependent on responsible registered DPs and should therefore be removed from having direct responsibility for Aggregate DER data. Additionally, 9c should be deleted to better align with what DPs are capable of collecting (i.e., aggregate DER data by storage types).

Dynamics Concerns:

Item 5 - It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for various modeling scenarios.

Item 7 – Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR. To address our concerns, we offer the following changes (clean format):

7. Inverter-Based Resource

a. Registered IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control [GO]

b. Aggregated capability of non-registered IBRs connect to the BPS including estimates related to momentary cessation, tripping, Ride-through, and frequency control [TOs]

Item 10 – TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed. To address our concerns, we offer the following changes (clean version):

10. Aggregate Distributed Energy Resource (DER) data

a. Estimates of aggregated DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. [DP, UFLS only DPs]

b. Indication whether DERs are part of any UFLS or UVLS schemes and provide estimates of the affected aggregated capacity on those schemes. [DP, UFLS only DPs]

Footnote concerns:

Footnote 1: EEI does not agree with Footnote 1. Data requirement obligations should be clearly specified within each sub-bullet of each column for both steady-state and dynamics to ensure responsible entities understand their roles.

Footnote 2: EEI suggests the following change to footnote 2 (clean version):

For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. The Distribution Provider is the responsible entity for providing this information, through coordination with the Transmission Owner.

Footnote 4: EEI does not agree that IBRs should be generically identified as storage devices. Instead, Battery Energy Storage System (BESS) should replace IBR in footnote 4 as changed below (clean version):

This includes battery energy storage systems, synchronous condensers, and pumped storage.

Footnote 5: Ambiguous terms like typical should not be included in NERC Reliability Standard. We additionally feel that it should be made clear the limits of TO responsibilities regarding unregistered IBRs as changed below (clean version).

The transmission owner is the responsible entity for collecting and providing aggregate data for unregistered IBRs that are not DERs and directly connected to their portion of the BPS.

Footnote 6: TO and DP have no ability to collect or provide aggregate data for DERs that are not connected directly to their system. If DER data is needed from unregistered DPs to preserve the reliability of the BPS, then those entities should be registered. The following change (clean version) has been provided to clarify what registered DPs are capable of providing under MOD-032:

The Distribution Provider is the responsible entity for collecting and providing aggregate data for DER connected to their distribution system.

Likes 0	
Dislikes 0	

Response

Sing Tay - AES - Indianapolis Power and Light Co. - 3

Answer	No
Document Name	

Comment

AES Indiana supports comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5

Answer	No
Document Name	

Comment

We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO

Answer	No
Document Name	

Comment

· The proposed MOD-032-2 modifications do not to address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models that accurately reflect the behavior of all IBRs).

· The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. There is disagreement regarding the enforceability of footnotes, which may leave certain entities vulnerable.

· P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) does not support the proposed revisions in MOD-032-2, specifically, R2.1. CEHE believes the Transmission Owner (TO) is not the appropriate registered entity to be responsible for providing estimations of unregistered load.	
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 that enforceable Reliability Standards should be reliant on external documents such as the document titled “ERO Approved Criteria for Acceptable Models” (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. Moreover, the Commission directed NERC “to develop **new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish** for each interconnection a uniform framework with modeling criteria” (emphasis added; FERC Order 901, P161). To better align with FERC Order 901, we offer the following comments and suggested edits in boldface below:

Requirement R1

Our edits are limited to part 1.2 in boldface below:

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator’s planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1 The data listed in Attachment 1, including the responsible entity for each required item.

1.2 Specifications for the following items for dynamic models submitted in accordance with Attachment 1:

1.2.1 A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.2.2 Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s), or a technical justification for the submission and use of user-written models if such models are permitted.

1.2.3 Criteria for any submitted user-written models including, at a minimum, documentation, and performance criteria to minimize the risk of non-convergence and other issues. The PC's user-written model criteria must be made available to all other TP/PCs within the Interconnection for review and comment, and approval where the usage of the user-written model represents a shared impact.

1.3 Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.3.1 Data format;

1.3.2 Level of detail to which equipment shall be modeled;

1.3.3 Case types or scenarios to be modeled; and

1.3.4 A schedule for submission of data at least once every 13 calendar months.

1.4 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

Footnote 1: For example, the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases.

Requirement R2

EEI does not support Requirement R2, part 2.1 because this requirement places compliance obligations on the TO that they have no practical method of fulfilling without the support of the unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While it is unclear how DER data from unregistered entities might impact BPS reliability, TO will be limited in their ability to fulfill their compliance obligations without the direct assistance and participation for unregistered DPs. To address this concern, guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DP does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DPs. We additionally offer some suggested boldface edits to Requirement R2 to add additional clarity:

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1 For unregistered Inverter-based Resource (IBR) data, the responsible TO, whose transmission system these resources are connected, shall develop estimates of the aggregated unregistered IBRs including estimated modeling data. The TO shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations.

2.2 For Distributed Energy Resource (DER), the responsible registered DP, whose distribution system these resources are connected, shall develop estimates of the aggregated unregistered DERs including estimated modeling data. The DP shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations. Upon completion, the data shall be sent to the responsible TO for collection and distribution to the responsible PC/TP.

2.3 For unregistered DPs the TO shall request DER data consistent with 2.2.

2.3.1 Where no data is provided by the unregistered DP, the TO shall develop an estimate of the DERs connected to the unregistered DP system. The TO shall also develop an explanation of the limitations of the aggregated data provided and the methods used for their estimations for distribution to the responsible PC/TP.

Attachment 1 Concerns: EEI offers the following comments and suggested edits (in boldface) to Attachment 1 below:

Item 2 – EEI requests clarification whether DPs are a suitable replacement for the LSE. While we agree that DPs are fully capable of providing demand data on distribution systems, they have no ability to provide load data on transmission systems.

Item 9 – EEI is of the opinion that 9c should be deleted because we do not agree that DER data by type is needed by the PC/TP. Additionally, given TOs can only supply DER rough estimate of aggregate DERs on unregistered systems, they have no ability to distinguish DERs by type.

Dynamics Concerns

Item 5 - EEI requests clarification whether DPs are a suitable replacement for the LSE. While we agree that DPs are fully capable of providing demand data on distribution systems, they have no ability to provide load data on transmission systems.

Item 7 – Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR. To address our concerns, we offer the following boldface edits to Item 7:

7. Inverter-Based Resource

a. Registered IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control **[GO]**

b. **Aggregated capability of non-registered IBRs connect to the BPS including estimates related to momentary cessation, tripping, Ride-through, and frequency control [TOs]**

Item 10 –EEI suggests clarifying TOs are only responsible for Aggregated DER data when there is no registered DP and they have no ability to assess UFLS impact from DERs unless provided by the unregistered DP. Additionally, UFLS only DPs should be added to Item 10

10. Aggregate Distributed Energy Resource (DER) data

a. **Estimates of aggregated** DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. **[DP, UFLS only DPs, TO (for non-registered DPs)]**

b. **I**ndication whether DER**s are part of any** UFLS or UVLS **schemes and provide estimates of the affected aggregated capacity on those schemes**. **[DP, UFLS only DPs]**

Footnote concerns

Footnote 1: EEI does not agree with Footnote 1. Data requirement obligations should be clearly specified within each sub-bullet of each column for both steady-state and dynamics to ensure responsible entities understand their roles.

Footnote 4: EEI does not agree that IBRs should be generically identified as storage devices. Instead, Battery Energy Storage System (BESS) should replace IBR in footnote 4. Note the following boldface edits:

This includes **battery energy storage systems**, synchronous condensers, and pumped storage.

Footnote 5: Ambiguous terms like typical should not be included in NERC Reliability Standard. We additionally feel that it should be made clear the limits of TO responsibilities regarding unregistered IBRs.

The transmission owner is the responsible entity for collecting and providing **aggregate** data for unregistered IBRs that are not DERs **and directly connected to their portion of the BPS.**

Footnote 6: TO and DP have no ability to collect aggregate data for DERs that are not connected directly to their system. Where DER data is needed from unregistered DPs to preserve the reliability of the BPS, then the TO should provide an estimate of the DERs connected to the unregistered DP system based on information provided by the unregistered DP or consistent with aggregated DER levels provided by other DPs connected to their system. The following boldface edits have been provided to clarify what TO are capable of providing under MOD-032:

The Distribution Provider is the responsible entity for collecting and providing **aggregate** data for DER connected to **their distribution** system. **Where no registered DP exists, the TO shall develop estimates on aggregated DER levels based on information obtained from the unregistered DP or consistent with DER levels provided by other DPs connected to their system.**	
Likes 0	
Dislikes 0	
Response	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	
Comment	
SIGE supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
No. *Reliability Standards to Address Inverter-Based Res.,* Order No. 901, 185 FERC ¶ 61,042 (2023) ("Order 901") calls for two different terms for purposes of determining the data and modeling of Inverter-Based Resources ("IBRs") whose owners are not registered and subject to compliance as Category 2 Generator Owners/Generator Operators (GO/GOPs): (1) "unregistered IBRs," whose data is to be reported individually and (2) IBR-Distributed Energy Resources ("IBR-DERs"), whose data is to be reported (or estimated) in the aggregate. Order 901 explicitly differentiates between "unregistered IBRs," which it describes as "IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards," and "IBR-DERs," which it describes as "IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk Power System." *Id.* P 4 n.14. The two draft standards address both types of IBRs but do so in ways that fail to achieve FERC's stated purpose of addressing the failure of existing standards to accurately account for the different way that IBRs respond to disturbances, as compared to synchronous generation. *Id.* P 37 (emphasis added) (footnotes omitted). *See also id.* PP 2-4, 50: Data that *accurately* represents IBRs is necessary to properly plan for, operate, and analyze IBR performance on the Bulk-Power System. Without data that accurately represents all IBRs, planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities are not able to develop system models that accurately account for the behavior of IBRs on their system, nor are they able to facilitate the analysis of Bulk-Power System disturbances. While there may be other issues with the proposed use of these terms, these comments focus on two flaws:	

(1) Defining the scope of the unregistered IBRs to be reported and modeled by use of a footnote referring to those IBRs connected to the Bulk-Power System ("BPS"), a vague term that is for FERC to define, rather than providing a clear cutoff consistent with the FERC-approved GO/GOP Category 2 registry criteria or the successfully balloted GO/GOP Category 2 Glossary definition. Such usage is not appropriate to determine the scope of what is to be covered by enforceable standards, and the resulting imprecision will invite double counts and gaps that will prevent the standards from achieving Order 901's reliability purposes.

(2) Instead of restricting the provision of data and modeling to IBR-DERs as Order 901 directs, relying on a DER definition that encompasses both IBR and non-IBR resources that are connected to the distribution system. This failure to have a definition focused solely on IBR-DERs threatens to undermine the express objective of Order 901 to accurately account for the behavior of IBRs. While the addition of Item 9.c under the "steady-state" column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards (*see, e.g.,* Item 10 under "dynamics" of that same Attachment; footnote 1 of draft MOD-033-3) invites confusion that could also carry over to other standards that are intended to reflect and account for the particular characteristics of IBRs.

Further details on concerns regarding these two definitions are provided in Questions 4 and 7.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Matt Lewis - Lower Colorado River Authority - 1

Answer	No
Document Name	

Comment

LCRA TSC supports the following comments submitted by EEI on behalf of its members:

Requirement 2
EEI does not support Requirement R2, Part 2.1 because this requirement places inappropriate compliance burdens on the TO that they have no practical method of fulfilling without the support of unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While EEI does not dispute that information from these unregistered entities may be needed and could impact BPS reliability, we do not agree that the answer is to place this compliance burden on TOs. Guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DP.

Attachment 1 concerns:
Steady State Item 9: TOs are entirely dependent on responsible registered DPs and should therefore be removed from having direct responsibility for Aggregate DER data.

Dynamics Item 7: Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR.

Dynamic Item 10: TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Constellation does not agree with the changes made and feels it creates ambiguity for Regional Entities on estimated unregistered IBR entities. Specifically, in 2.1 a caveat for data requirements for unregistered units is provided which allows Regional Entities to provide estimates of data. This is asking for data that would not be relevant for models if it is not accurate data and could call for ambiguity between regions on the amount of data required. Constellation suggests striking the term unregistered to reduce ambiguity.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Joseph Scott - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

LCRA supports the following comments submitted by EEI on behalf of its members:

Requirement 2

EEI does not support Requirement R2, Part 2.1 because this requirement places inappropriate compliance burdens on the TO that they have no practical method of fulfilling without the support of unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While EEI does not dispute that information from these unregistered entities may be needed and could impact BPS reliability, we do not agree that the answer is to place this compliance burden on TOs. Guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DP.

Attachment 1 concerns:

Steady State Item 9: TOs are entirely dependent on responsible registered DPs and should therefore be removed from having direct responsibility for Aggregate DER data.

Dynamics Item 7: Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR.

Dynamic Item 10: TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	

Constellation does not agree with the changes made and feels it creates ambiguity for Regional Entities on estimated unregistered IBR entities. Specifically, in 2.1 a caveat for data requirements for unregistered units is provided which allows Regional Entities to provide estimates of data. This is asking for data that would not be relevant for models if it is not accurate data and could call for ambiguity between regions on the amount of data required. Constellation suggests striking the term unregistered to reduce ambiguity.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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 has voted “yes” on previous ballots related to MOD-032 modifications and supports most of the standard revisions. However, significant changes to NERC’s external document “ERO Approved Criteria for Acceptable Models document” since the last MOD-032 revision, specifically the inclusion of criteria modifications that could impact a Registered Entity’s compliance, highlight our significant concern with the new MOD-032 revisions.

There are simple changes that NERC can make to MOD-032 to garner our support, and specifically that includes moving any criteria in the “ERO Approved Criteria for Acceptable Models document” within the standard and converting the external model reference to a “ERO Approved Acceptable Models list” consistent with FERC 901 requirements. Additional comments are included in question 6.

Southern Company additionally recommends the minor revisions below for enhanced clarity:

- On Requirement 1 – add the word “Functional” in front of entities to make it clear the standard is referencing NERC Functional Entities.
- On Requirement 2 – add the word “Functional” in front of entities to make it clear the standard is referencing NERC Functional Entities.

Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No

Document Name	
Comment	
The standard should also address data for DERs where there is no associated registered DP. P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
2 years implementation to collect all DERs on the distribution system is likely not feasible considering the standard includes rooftop solar and other types of DERs connected behind the meters. The standard further requires the dynamics modeling data that is often not available for DERs and it would likely take significant time for Distribution Providers to gather and develop these modeling data.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_ATC.docx
Comment	
Please see question 1 comments (highlighted) in attached document.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports the comments of WAPA and Bonneville Power.	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The NAGF would like to see MOD-032 modified to require the TP and PC to request data from those entities they want data from, rather than expect all other entities to track what the TP and PC are requiring. With the addition of Generator Owners that may or may not be interconnected to any NERC-registered entity, the TP and PC need to actively engage with these entities to ensure the TP and PC are able to get the best data possible and provide feedback as to what is needed/acceptable, etc. Additionally, the NAGF supports the comments by EEI.	
Likes 0	
Dislikes 0	
Response	

Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
• The proposed MOD-032-2 modifications do not address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models accurately reflect the behavior of all IBRs). • The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. • P141 directs NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission	

operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	

Comment

Invenergy does not agree with the revisions to MOD-032-2. Specifically, MOD-032-2 is not self-contained and requires entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that the "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	No
Document Name	

Comment

Invenergy does not agree with the revisions to MOD-032-2. Specifically, MOD-032-2 is not self-contained and requires entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that the "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2.

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 effort put forth by the SDT to address the directives of FERC Order 901; however, we have concerns with the data collection burden being placed on responsible entities (as identified in Requirement R1 Part 1.1). Much of the industry is already operating with limited resources, and many (if not most) entities are currently short-staffed. This is particularly true for smaller entities such as electric cooperatives. In short, we are not convinced that this level of data collection is a cost-effective approach to improving grid reliability and reducing risk.

Lastly, we would like to point out a minor discrepancy between the "redline" and "clean" versions of this draft of MOD-032-2. Requirement R2 Part 2.1 in the "clean" version is missing a portion of the language contained in the "redline" version. The phrase "…Energy Resource (DER) data, the responsible entity shall estimate the modeling…" do not appear in the "clean" version of Part 2.1.

Likes 0	
Dislikes 0	

Response

Colten Mitchell - Indiana Municipal Power Agency - 4

Answer	No
Document Name	

Comment

No. *Reliability Standards to Address Inverter-Based Res.,* Order No. 901, 185 FERC ¶ 61,042 (2023) ("Order 901") calls for two different terms for purposes of determining the data and modeling of Inverter-Based Resources ("IBRs") whose owners are not registered and subject to compliance as Category 2 Generator Owners/Generator Operators (GO/GOPs): (1) "unregistered IBRs," whose data is to be reported individually and (2) IBR-Distributed Energy Resources ("IBR-DERs"), whose data is to be reported (or estimated) in the aggregate. Order 901 explicitly differentiates between "unregistered IBRs," which it describes as "IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards," and "IBR-DERs," which it describes as "IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk Power System." *Id.* P 4 n.14. The two draft standards address both types of IBRs but do so in ways that fail to achieve FERC's stated purpose of addressing the failure of existing standards to accurately account for the different way that IBRs respond to disturbances, as compared to synchronous generation. *Id.* P 37 (emphasis added) (footnotes omitted). *See also id.* PP 2-4, 50:

Data that *accurately* represents IBRs is necessary to properly plan for, operate, and analyze IBR performance on the Bulk-Power System. Without data that accurately represents all IBRs, planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities are not able to develop system models that accurately account for the behavior of IBRs on their system, nor are they able to facilitate the analysis of Bulk-Power System disturbances.

While there may be other issues with the proposed use of these terms, these comments focus on two flaws:

(1) Defining the scope of the unregistered IBRs to be reported and modeled by use of a footnote referring to those IBRs connected to the Bulk-Power System ("BPS"), a vague term that is for FERC to define, rather than providing a clear cutoff consistent with the FERC-approved GO/GOP Category 2 registry criteria or the successfully balloted GO/GOP Category 2 Glossary definition. Such usage is not appropriate to determine the scope of what is to be covered by enforceable standards, and the resulting imprecision will invite double counts and gaps that will prevent the standards from achieving Order 901's reliability purposes.

(2) Instead of restricting the provision of data and modeling to IBR-DERs as Order 901 directs, relying on a DER definition that encompasses both IBR and non-IBR resources that are connected to the distribution system. This failure to have a definition focused solely on IBR-DERs threatens to

undermine the express objective of Order 901 to accurately account for the behavior of IBRs. While the addition of Item 9.c under the “steady-state” column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards (*see, e.g.,* Item 10 under “dynamics” of that same Attachment; footnote 1 of draft MOD-033-3) invites confusion that could also carry over to other standards that are intended to reflect and account for the particular characteristics of IBRs.

Further details on concerns regarding these two definitions are provided in Questions 4 and 7.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)

Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx

Comment

Southwest Power Pool abstains from the response to this question.

The ERO Approved Criteria for Acceptable Models document referenced in the proposed Requirement R1, Part 1.2 establishes some common-sense usability requirements, but it is unclear how it might be interpreted and enforced. For example, if an auditor determines a model manual is unacceptable in the course of a compliance engagement, it is unclear which entity would be considered to have violated the standard: the model submitter, or the planner that accepted the model. If a model and its associated documentation are deemed acceptable by the PC and TP, the model should be considered acceptable.

Furthermore, the usability requirements identified under Chapter 2 within the Usability Requirements section (pgs. 3-4) of the document are mostly administrative requirements that address model documentation. The usability requirements identified in Chapter 5 within the Technical Rationale section (pg. 8) are arguably more important for actually being able to perform simulations, but it is not clear how enforceable they would be. Ultimately, it seems like a violation of the Criteria for Acceptable Models document could be better addressed as an identified technical concern under Requirement R3 and most of the substantive parts of the criteria document could be consolidated into the existing, separate Technical Rationale to detail examples of

issues that would need to be addressed under Requirement R3. Thus, the ISO/RTO Council (IRC) Standards Review Committee (SRC) suggests that the proposed Requirement R1, Part 1.2 be deleted and a new Part 1.4 be added that reads as follows:

"1.4. Specifications of the following items for dynamic model submissions:

1.4.1. A list of unacceptable models[1], which are not to be submitted unless no alternative model is available;

1.4.2. Required submission of standard library models recognized by the software utilized to create the interconnection-wide case(s) and/or user-written models; and

1.4.3. Criteria for any submitted user-written models, including, at a minimum, model documentation and instructions for model setup and use to minimize the risk of non-convergence and other issues.

Footnote 1: For example, data requirements and reporting procedures may point to the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases."

The proposed language above provides explicit flexibility for PC/TP to require generic models, user-defined models, or both. In conjunction with Requirement R3, this addresses the FERC directives in a more enforceable and easily understood manner than the currently proposed use of a separate ERO criteria document.

Additionally, proposed footnote 1 (which would become footnote 2 if the Part 1.4 language proposed above is adopted) within Requirement R2, Part 2.1 should be modified to read as follows: *"As used in this standard, the phrase 'unregistered IBR' refers to an IBR that is not a DER and does not meet mandatory NERC registration criteria."* The drafting team has already acknowledged the ambiguities associated with attempting to define DER based on "connection to the BPS." Using the concept of BPS connection here introduces those same ambiguities.

Finally, Requirement R3, Part 3.1 should be modified to read as follows: *"Provide either updated data or an explanation with a technical basis for maintaining the current data that resolves the technical concern."*

This added language is necessary to ensure technical concerns are adequately addressed. For example, if the technical concern is suspicious data, a technical basis for maintaining current data may be acceptable in some circumstances but would not resolve the underlying issue if the model crashes or does not initialize.

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

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	

Comment
The use of aggregated, generic data to model IBR's may do more harm than good. Accurate data is required to reliably meet the FERC order. Perhaps generic data is the first step but caution must be taken to avoid consequential, incorrect analysis.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	

Comment
For this question, 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

John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	

Comment
ISO New ENgland signs onto all of the ISO/RTO Standards Review Committee (SRC) Comments

Likes 0	
Dislikes 0	

Response

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	

As noted by IRC, SPP supports the following portion of the response:

The ERO Approved Criteria for Acceptable Models document referenced in the proposed Requirement R1, Part 1.2 establishes some common-sense usability requirements, but it is unclear how it might be interpreted and enforced. For example, if an auditor determines a model manual is unacceptable in the course of a compliance engagement, it is unclear which entity would be considered to have violated the standard: the model submitter, or the planner that accepted the model. If a model and its associated documentation are deemed acceptable by the PC and TP, the model should be considered acceptable.

Furthermore, the usability requirements identified under Chapter 2 within the Usability Requirements section (pgs. 3-4) of the document are mostly administrative requirements that address model documentation. The usability requirements identified in Chapter 5 within the Technical Rationale section (pg. 8) are arguably more important for actually being able to perform simulations, but it is not clear how enforceable they would be. Ultimately, it seems like a violation of the Criteria for Acceptable Models document could be better addressed as an identified technical concern under Requirement R3 and most of the substantive parts of the criteria document could be consolidated into the existing, separate Technical Rationale to detail examples of issues that would need to be addressed under Requirement R3. Thus, the ISO/RTO Council (IRC) Standards Review Committee (SRC) suggests that the proposed Requirement R1, Part 1.2 be deleted and a new Part 1.4 be added that reads as follows:

"1.4. Specifications of the following items for dynamic model submissions:

1.4.1. A list of unacceptable models{C}[1], which are not to be submitted unless no alternative model is available;

1.4.2. Required submission of standard library models recognized by the software utilized to create the interconnection-wide case(s) and/or user-written models; and

1.4.3. Criteria for any submitted user-written models, including, at a minimum, model documentation and instructions for model setup and use to minimize the risk of non-convergence and other issues.

Footnote 1: For example, data requirements and reporting procedures may point to the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases."

The proposed language above provides explicit flexibility for PC/TP to require generic models, user-defined models, or both. In conjunction with Requirement R3, this addresses the FERC directives in a more enforceable and easily understood manner than the currently proposed use of a separate ERO criteria document.

Additionally, proposed footnote 1 (which would become footnote 2 if the Part 1.4 language proposed above is adopted) within Requirement R2, Part 2.1 should be modified to read as follows: *"As used in this standard, the phrase 'unregistered IBR' refers to an IBR that is not a DER and does not meet mandatory NERC registration criteria."* The drafting team has already acknowledged the ambiguities associated with attempting to define DER based on "connection to the BPS." Using the concept of BPS connection here introduces those same ambiguities.

Likes 0	
Dislikes 0	

Response

Scott Thompson - TXNM Energy - 3

Answer	No
Document Name	

Comment

TXNM agrees with the comments made by EEI, in addition:

1. The proposed MOD-032-2 modifications do not to address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models that accurately reflect the behavior of all IBRs).
2. The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. There is disagreement regarding the enforceability of footnotes, which may leave certain entities vulnerable.
3. P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	

Comment

Consistent with FERC's Order 901 directive to consider data sharing requirements for transmission owners to provide data to generators, MOD-032-2 should include a requirement for transmission owners to provide data to generator owners and operators to support accurate modeling and performance, e.g., short circuit data, grid data for offshore wind, information on other power electronic devices around the IBR plant, and voltage harmonics. In many cases this transmission provider data is necessary for generator owners to be able to determine generator settings and comply with

MOD-032-2. The Consideration of FERC Order 901 Directives document argues that such a requirement is unnecessary as processes exist for obtaining that data, though in many regions they do not or are inadequate.	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
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; John Nierenberg, 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	
Tacoma Power concurs that the proposed MOD-032 modifications address FERC Order 901 and appreciates the explanation provided in the technical rationale as to when the SDT decided to expand beyond the FERC directive. This additional explanation helped explain what changes directly supported the directives versus those changes that were added as improvements. For example, explaining why both synchronous and asynchronous resources were included in the DER definition, even though the FERC directive only mentioned IBR-DERs.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	

Comment	
MRO recommends revising R2.1 to avoid use of the term "unregistered Inverter-based Resource" in R2, part 2.1. The current wording is inconsistent with the ERO's current practice of using "registered" to refer to entities and not equipment, Facilities, or resources owned by entities.	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool's comments.	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) question 1.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	

It looks like in MOD-032, in the Compliance section 1.2 the word "directive" should be "directed."	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
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; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
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; Kris Kirkegaard, 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	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	

n/a

Likes 0	
Dislikes 0	

Response

Greg Sorenson - ReliabilityFirst - 10 - RF

Answer	
Document Name	

Comment

The proposed changes allow the Planning Coordinators to add additional detail to the modeling requirements to ensure DER data is modeled to allow for appropriate system planning studies

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EPRI agrees with the intent of the proposed MOD-032-2 modifications but abstains from answering with "Yes" or "No" to this question.

EPRI research informs the potential need and feasibility of changes to MOD-032-2, see for example:

- *Transmission Planning Considerations for DER Wholesale Market Participation: An EPRI FO2222 Phase 1 Collaborative Report.* EPRI. Palo Alto, CA: 2022. 3002020592.
- *EPRI Technology Transfer to NERC SPIDER Working Group: Informing NERC Stakeholder Discussions and Publications on System Planning Impacts of Distributed Energy Resources in the Years 2022-2024.* EPRI. Palo Alto, CA: 2025. 3002031525.
    - Including the reports listed under “Related Material” on that page.

EPRI worked with vendors of fundamental-frequency phasor-domain transient (PDT) modeling domain transmission planning software since 2019 and all of them have implemented the so-called *Aggregate DER (DER_A) Model* in their positive-sequence phasor domain tools:

- *The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies: 2019 Update.* EPRI. Palo Alto, CA: 2019. 3002015320.

EPRI (and other entities) have tested and applied the DER_A model extensively, and we published the following report in 2021:

- Analyzing the Impact of Aggregated DER Behavior on Bulk Power System Performance – A Summary of Three Case Studies. EPRI. Palo Alto, CA: 2021. 3002019445.

Likes 0	
Dislikes 0	
Response	

2. Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system? If not, what entity would be in a better position to provide that data and add justification?

Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	
TXNM Energy feels that the Resource Planner is in a better position to aggregate DER information than the transmission owner. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. If unregistered DER data is critical to the reliability of the BPS, then unregistered DPs that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria.	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
The responsibility of TOs to gather DER data from unregistered DP's places a compliance risk on them. Unregistered entities have no compliance obligation to provide the necessary data, making it challenging for TOs to fulfill their responsibilities.	
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	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The Transmission Owner (TO) is not always the most suitable entity to collect and provide data for Distributed Energy Resources (DER), particularly in instances where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. If unregistered DER data is critical to the reliability of the BPS, then unregistered DPs that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria such as DP – DER, similar to DP-UFLS.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	

Exelon supports the comments submitted by the EEI.

Additionally, TPs and PCs may have more authority to obtain data from unregistered entites than the connected TOs.

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	No
Document Name	

Comment

LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.

Likes 0	
Dislikes 0	

Response

James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

The unregistered entity is the best entity to request data from, and there is no prohibition to requesting data from unregistered entities. The NAGF notes this language in TOP-003-5 "…including non-BES data and external network data as deemed necessary by the Transmission Operator." This does not appear to limit the TOP to only information from registered entities. It appears to say that the TOP should ask for the data it needs, even if the data is not BES data. The TP and PC should be expected to do the same, however, they should not be held accountable for the accuracy of estimates provided whenever the unregistered DPs decline a request for data.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	No
Document Name	

Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports the following comments submitted by EEI on behalf of its members.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC does not agree that the TO should be held responsible for collecting or providing data on DERs where they have no authority and ability to collect data, and have not interconnected those resources. If this data is necessary to analyze and determine the reliability of the BPS then the unregistered DPs that interconnect DER resources should be registered.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	

Comment
The entity which the DER is directly interconnected to.

Likes 0	
Dislikes 0	

Response

Joseph Scott - Lower Colorado River Authority - 5	
Answer	No
Document Name	

Comment
LCRA supports EEI comments which state: EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	

Comment
Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.

Likes 0	
Dislikes 0	

Response

Matt Lewis - Lower Colorado River Authority - 1	
Answer	No
Document Name	

Comment
LCRA TSC supports EEI comments which state: EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.

Likes 0	
Dislikes 0	

Response

Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion	
Answer	No
Document Name	

Comment
Dominion Energy supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	

Comment
SIGE supports EEI comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment	
EEI does not dispute that TOs are the only registered entity available to provide data from unregistered DPs. However, they are limited in their ability to obtain and provide this data because they have no ability to compel unregistered DPs to provide such data. Moreover, the TO should be viewed simply as a conduit for DER data provided by the unregistered DPs and should not be held accountable for the accuracy of estimates provided whenever the unregistered DPs decline a TO's request for data.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE believes the TO is not the appropriate registered entity to be responsible for providing estimations of unregistered load. CEHE, as a TO, does not have visibility into an unregistered entity's systems to provide an estimate of the data at any level of accuracy.	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, 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	
Imperial Irrigation District agrees with the comments provided by the Western Power Pool.	
Likes 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	No

Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The Transmission Owner (TO) is not always the most suitable entity to collect and provide data for Distributed Energy Resources (DER), particularly in instances where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. If unregistered DER data is critical to the reliability of the BPS, then unregistered DPs that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria.	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	No
Document Name	
Comment	
The Transmission Owner (TO) is not always the most appropriate entity to collect and provide data for Distributed Energy Resources (DER) in cases where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have been involved in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. As a result, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. For example, while Seattle City Light functions as both a TO and a distribution load-serving entity, it still may not have access to detailed inverter information for DERs that are already installed. In such cases, significant assumptions and estimations would be required to model these resources accurately.	
Likes 0	
Dislikes 0	

Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	
No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
AES Indiana supports comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
The DER's at the connection point should handle the data collection and reporting responsibility	
Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	

AZPS supports the following comments provided by EEI on behalf of its members:

EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.

Likes 0	
Dislikes 0	

Response

Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	No
Document Name	
Comment	

No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power supports EEI's feedback.

Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	

The Transmission Owner (TO) is not always the most suitable entity to collect and provide data for Distributed Energy Resources (DER), particularly in instances where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. The Transmission Owner is not involved in the connection process for DER, and therefore does not have the data necessary for DER modelling. If there are reliability impact to the BPS due to DER connected where there are no DP, it is suggested that the registration criteria for DP be updated to ensure that all applicable entities that could have BPS impact are registed with NERC. This could be done as an initiative similar to what was done for IBR registration.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

Nextera supports comments provided by EEI

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

The redlines do not delineate that the TO is the responsible entity to accomplish this effort. Recommend TOP be the responsible party.

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 EEI.	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's comments to this question. Black Hills Corporation agrees that the TO should not be held responsible for collecting data on DERs described above. The TO has no direct responsibility or control over these unregistered DER's and do not have direct knowledge of DER connections on the unregistered DP's systems.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
The TO does not always have visibility into DER systems unless they were directly involved in the interconnection agreements.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	

Comment
The revised standard seeks to capture 'unregistered IBR' and 'aggregate DER' steady state and dynamics data for various planning horizons. Unregistered IBR is defined only in this standard. It may be more reasonable for the Planning Coordinator to require various data from 'unregistered IBR's' through existing interconnection requirements rather than to require that all unregistered IBR's provide this data to the PC as a compliance requirement. Alternatively, GO/Gop Category 2 or a new Registration should hold that responsibility.

Likes 0	
Dislikes 0	

Response

Daren Brubaker - Seattle City Light - 6	
Answer	No
Document Name	

Comment
I understand SCL is TO and DP, but I think we still need to comment on this. No, the Transmission Owner (TO) is not always the most appropriate entity to collect and provide data for Distributed Energy Resources (DER) in cases where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have been involved in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. As a result, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. For example, while Seattle City Light functions as both a TO and a distribution load-serving entity, it still may not have access to detailed inverter information for DERs that are already installed. In such cases, significant assumptions and estimations would be required to model these resources accurately.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5	
Answer	No
Document Name	

Comment
AEP continues to believe that the most efficient and technically appropriate path for implementing this proposed standard is to align with existing registration and data provision frameworks. Specifically, where Distributed Energy Resources (DERs) interconnect and provide data relevant to MOD-032 Attachment One, the entities possessing that data should be properly registered and held accountable under the NERC Functional Model. As with existing standards requiring Generator Owners (GOs) or Distribution Providers (DPs) to provide planning and modeling data, those entities who control or aggregate DER fleets and are capable of furnishing the required information should be registered accordingly. While it remains unclear whether existing Functional Entities are universally sufficient, or whether a new DER-specific Functional Entity class may be warranted, the need for

clear accountability is critical.

To clarify, AEP does not support requiring every individual rooftop solar customer to register as a Functional Entity. Instead, FERC Order No. 2222 Aggregators of DERs (DER Aggregators) could be envisioned as the appropriate responsible parties. These entities are well-positioned to coordinate with their constituent DERs, consolidate the necessary modeling and planning data, and meet compliance obligations.

In our view, the responsibility for MOD-032 data collection and compliance could rest with the DER aggregator, who in turn must coordinate with the Distribution Provider and Transmission Owner for appropriate data sharing and validation. This structure promotes scalability, efficiency, and consistency across jurisdictions, especially considering that DER participation can span both Federal and State regulatory boundaries.

NERC should consider how this evolving aggregator model intersects with the Functional Model and explore registration or oversight pathways that ensure these entities are held accountable without placing undue burdens on small-scale DER owners.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES adopts EEI's comments for MOD-032-2.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports EEI comments which state:

EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.

Likes 0	
Dislikes 0	

Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's response to question 1.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
The appropriate party would be the entity that worked with the DER to create the interconnection agreement. This would include preliminary modeling and verification of performance. The SDT's question is unclear; if the TO worked to interconnect the DER it would be the correct responsible entity, however if the LSE, GO or DP was responsible for the interconnection of the DER they would be the most responsible entity. The SDT also fails to state the voltage level of the interconnection. If the voltage level is above the 100kV threshold, the TO would be responsible, however below that voltage the LSE or DP would most likely be the appropriate entity. Since LSEs are no longer part of the NERC registry, the SDT should submit a SAR requesting that LSEs are once again required to be responsible entities. This may better align the standards with the responsible entities in practice.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	

though it is not clear what accountability the TO has for collecting and providing data for DER. Within Ontario there are no DPs as per the IESO Market Rules. I don't think there is another entity that is in a better position to collect and provide the data

Likes 0	
Dislikes 0	

Response

Greg Sorenson - ReliabilityFirst - 10 - RF

Answer	Yes
Document Name	

Comment

Where there is no associated DP, the TO is usually in the best position to collect and provide DER data.

Likes 0	
Dislikes 0	

Response

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	Yes
Document Name	

Comment

SPP supports the comments filed by the SRC regarding this question.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

For this question, ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	
Response	
Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	Yes
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	
The best long-term solution would be for NERC to expand DP registration criteria (or create DER-only DP registration criteria) such that no DER would be connected to the distribution system without being associated with a registered DP.	
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 agrees with the flexibility proposed in the current draft language.	
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	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
While Oncor Electric Delivery Company LLC (“Oncor”) agrees with the question as phrased, Oncor would like to note that ideally the DER owner would maintain responsibility for adhering to data-sharing requirements. Oncor recognizes, however, that this may not be a practical solution given the broad applicability of the DER definition proposed in the standard. Oncor would also like to propose an alternative approach for the SDT’s consideration – in the event that an unregistered DP is between the DER connection point and the TO’s system, instead of placing the data collection responsibility on the TO, there could instead be a mandate for any such DPs to register. This would keep the data sharing requirements with the DP who may be better positioned to provide more accurate data than the TO.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emma Halilovic - Hydro One Networks, Inc. - 1	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
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	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
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; Kris Kirkegaard, 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	

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
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	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
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	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6	
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; John Nierenberg, 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	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EPRI is agnostic as to this question about whom may be the appropriate responsible entity for collecting and providing data and we abstain from answering with "Yes" or "No" to this question.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	

Document Name	
Comment	
No, the Transmission Owner (TO) is not always the most appropriate entity to collect and provide data for Distributed Energy Resources (DER) in cases where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have been involved in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. As a result, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. For example, while Seattle City Light functions as both a TO and a distribution load-serving entity, it still may not have access to detailed inverter information for DERs that are already installed. In such cases, significant assumptions and estimations would be required to model these resources accurately.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the proposed IRO-010-5 and TOP-003-8 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI comments which state:

Consistent with EEI concerns as stated in our response to question 1, we do not agree that enforceable Reliability Standards should be reliant on external documents such as the document titled “ERO Approved Criteria for Acceptable Models” (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. To address our concerns with this issue in both IRO-010-6 and TOP-003-8 we offer the following comments and edits in boldface:

IRO-010-6 Concerns

Requirement R1: The following suggested changes to IRO-010-6, Requirement R1, part 1.5.3 (in boldface) align with our proposed changes to MOD-032 and provide RCs with similar capabilities as provided to PCs in that standard. We believe these changes will satisfy FERC Order 901 directives, place the criteria within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection.

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to.:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization; Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data. for the following items for dynamic models submitted in accordance with Attachment 1:

1.5.3.1. A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.5.3.2. Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s) and/or user-written models along with an explanation of the use case(s) for each model type.

Criteria for any submitted user-written models including, at a minimum, documentation and performance criteria to minimize the risk of non-convergence and other issues. The RC's user-written model criteria must be made available to all other RCs within the Interconnection for review and comment, and approval where the user-written model represents a shared impact.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES adopts EEI's comments for IRO-010-5 and TOP-003-8

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; John Nierenberg, 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 does not agree that TOP-003-8 R1.5.3 and R2.5.3 are necessary to “further enhance real-time visibility of Bulk-Power System operations” (FERC Directive p 86). The changes to TOP-003-8 R1.1 and R2.1 adequately address this FERC directive. The proposed new sub-Requirements R1.5.3 and R2.5.3 are not related to this directive, as the data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility. Tacoma Power does not agree with expanding the scope of TOP-003-8 to include model submissions and requesting modeling data. TOP-003 should continue to focus on the data needed for real-time operations (e.g. RTAs and OPAs). The TOP-003 sub-Requirements related to requesting modeling data in R1.5.3 and R2.5.3 should be removed from TOP-003-8. Additionally, TOP-003-8 R2.5.3 is redundant to MOD-032-2 R2. If a Requirement is needed to ensure the TOP is capable of requesting modeling data, then Tacoma Power recommends modifying MOD-032 and add the TOP as a functional entity in this Standard. If the SDT determines that the scope of TOP-003-8 should be expanded to include modeling data, then Tacoma Power recommends modifying TOP-003-8 R1.5.3 to clarify that the TO is the appropriate responsible entity for collecting and providing modeling data for DERs where there is no associated registered DP (and not the TOP or BA), similar to the approach taken in the MOD-032-2 redline. TOP-003-8 would then need to be modified to include the TO as a functional entity.

Likes 0	
Dislikes 0	

Response

Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	

Comment
Chelan PUD does not agree that TOP-003-8 R1.5.3 and R2.5.3 are necessary to “further enhance real-time visibility of Bulk-Power System operations” (FERC Directive p 86). The proposed new sub-Requirements for TOP-003 R1.5.3 and R2.5.3 are not related to this directive, as the data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility. Chelan PUD does not agree with expanding the scope of TOP-003-8 to include model submissions and requesting modeling data. TOP-003 should continue to focus on the data needed for real-time operations (e.g. RTAs and OPAs). CHPD agrees to the recommended changes for IRO-010-5.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	

Comment

Proposed modifications to IRO-010-5 and TOP-003-8 both reference the ERO Criteria for Acceptable Models. See our comments for Question 1.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

Requirement R1 Part 1.1 of the draft IRO-010-6 and TOP-003-8 now specifies IBR-specific “data and parameters”. It is not clear if the drafting team identified a material difference that would mandate IBR-specific data **and** IBR-specific parameters as necessary condition for compliance. The addition in Part 1.5.3 clarifies that the data specification must include methods to provide data that include requirements for model submissions in accordance with the Criteria for Acceptable Models.

BC Hydro suggests that using “IBR-specific data” in Part 1.1. in conjunction with the additional Part 1.5.3 is sufficient; otherwise, we request that the drafting team provides additional clarity on what would constitute adequate and sufficient evidence to demonstrate compliance for IBR data and IBR parameters.

Requirement R1 Part 1.5.3 of the draft IRO-010-6 and TOP-003-8 (as well as R2 Part 2.5.3 of TOP-003-8) mandates that the data spec must include methods to provide data that include “requirements for model submissions in accordance with the Criteria for Acceptable Models”. BC Hydro’s understanding (supported by the Technical Rationale) is that the intent here is to mandate that data models must be in accordance with the Criteria for Acceptable Models, rather than their submission, which must be in accordance with the method specified pursuant to Part 1.5. Revised wording for clarity is provided below:

1.5.3 Requirements that data models are in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization.

Likes 0	
Dislikes 0	

Response

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI’s comments to this question for similar reasoning used for question 1. We agree with their suggested changes to IRO-010-5 and TOP-003-8. Black Hills Corporation would support combining the requirements from IRO-010-5 into TOP-003-8 and retiring IRO-010-5.

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 EEI.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation abstains from this question as it does not have IBR/DER resources.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Nextera supports comments provided by EEI	
Likes 0	
Dislikes 0	

Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
(1) The added sub-requirement 1.5.3 should be removed from this standard as it pertains to data and information collection, not model submissions. The data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility This requirement is already addressed in MOD-032-2 R1 (sub-requirement 1.2). (2) The statement “Inverter-based Resource (IBR)-specific data and parameters” added to section 1.1 should be removed or more inclusive of including all other facilities, of which IBR’s are a subset. It is suggested that the statement be augmented to the following, “including Generator, FACTS, aggregate DER and Inverter-based Resource (IBR)-specific data and parameters”.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI and MRO’s NERC Standards Review Forum’s (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	

AES Indiana supports comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	No
Document Name	
Comment	
Support Tacoma Power's comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The added sub-requirement 1.5.3 should be removed from this standard as it pertains to data and information collection, not model submissions. The data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility This requirement is already addressed in MOD-032-2 R1 (sub-requirement 1.2).	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, 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	

For TOP-003-8: Imperial Irrigation District agrees with the comments provided by Tacoma Power.

Likes 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

Consistent with EEI concerns as stated in our response to question 1, we do not agree that enforceable Reliability Standards should be reliant on external documents such as the document titled “ERO Approved Criteria for Acceptable Models” (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. To address our concerns with this issue in both IRO-010-6 and TOP-003-8 we offer the following comments and edits in boldface:

IRO-010-6 Concerns

Requirement R1: The following suggested changes to IRO-010-6, Requirement R1, part 1.5.3 (in boldface) align with our proposed changes to MOD-032 and provide RCs with similar capabilities as provided to PCs in that standard. We believe these changes will satisfy FERC Order 901 directives, place the criteria within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection.

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

{**1.3.2.2.** historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to.:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data. for the following items for dynamic models submitted in accordance with Attachment 1:

1.5.3.1. A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.5.3.2. Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s) and/or user-written models along with an explanation of the use case(s) for each model type.

1.5.3.3. Criteria for any submitted user-written models including, at a minimum, documentation and performance criteria to minimize the risk of non-convergence and other issues. The RC's user-written model criteria must be made available to all other RCs within the Interconnection for review and comment, and approval where the user-written model represents a shared impact.

1.5.4 Provisions to update or correct data and information, as applicable or necessary.;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

TOP-003-8 Concerns

Requirement R1: The following suggested changes to TOP-003-8, Requirement R1, part 1.5.3 (in boldface) align with our proposed changes to MOD-032 and provide RCs with similar capabilities as provided to PCs in that standard. We believe these changes will satisfy FERC Order 901 directives,

place the criteria within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection.

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2 Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3 Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1 capability and availability;

1.3.1.2 fuel supply and inventory concerns;

1.3.1.3 fuel switching capability; and

1.3.1.4 environmental constraints

1.3.2 Generating unit(s) minimum:

1**.3.2.1** design temperature; or

1.3.2.2 historical operating temperature; or

1.3.2.3 current cold weather performance temperature determined by an engineering analysis.

1.4 Identification of a mutually agreeable process for resolving conflicts.

1.5 Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following:

1.5.1 Specified deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data for the following items for dynamic models submitted in accordance with Attachment 1:

1.5.3.1 A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.5.3.2 Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s) and/or user-written models along with an explanation of the use case(s) for each model type.

1.5.3.3 Criteria for any submitted user-written models including, at a minimum, documentation, and performance criteria to minimize the risk of non-convergence and other issues.

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

Footnote 1: For example, the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases.

Requirement 2: EEI is of the opinion that Requirement R2, subpart 2.54 was added in error and should be removed. It is our understanding that the BA is not responsible for Steady State, Dynamic or Short Circuit modeling and therefore has not useful utility.

Likes 0	
Dislikes 0	

Response

Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF

Answer	No
Document Name	

Comment

SIGE supports EEI comments

Likes 0	
Dislikes 0	

Response

Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment	
Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
NIPSCO also supports MISO's comments referenced below: "NERC Standards often default to the lowest common denominator in terms of data quality, which can compromise model accuracy. To ensure more reliable and representative system models, NERC should strengthen data submission requirements. Specifically, MOD-032 should explicitly state that submitted data must accurately reflect how equipment is configured and operates in the field." And, "Consistent with the response to Q1 above providing a superior alternative to the separate ERO criteria document, the language in IRO-010-6 Requirement R1, Part 1.5.3; TOP-003-8 Requirement R1, Part 1.5.3; and TOP-003-8 Requirement R2, Part 2.5.3 should be changed to read as follows: Requirements for model submissions consistent with the model submitted for planning purposes in accordance with MOD-032; Referencing MOD-032 instead of a separate ERO criteria document satisfies FERC's directives in Order No. 901 by ensuring consistency between operations models and planning models, while also leveraging model quality and accuracy requirements associated with MOD-032 submissions."	
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; Kris Kirkegaard, 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 sub-Requirements R1.5.3 and R2.5.3 in TOP-003-8 are not necessary to enhance "***real-time visibility***" [emphasis added] of Bulk Power System operations as outlined in the FERC Directive (p. 86). We feel that the changes made to Requirements R1.1 and R2.1 adequately address this FERC directive.

The proposed new sub-Requirements R1.5.3 and R2.5.3 appear to focus on data collected for modeling purposes, specifically in relation to the "ERO Approved Criteria for Acceptable Models" document, rather than contributing to real-time visibility. Additionally, sub-Requirement R2.5.3 seems to duplicate Requirement R2 of MOD-032-2.

We suggest that the scope of TOP-003-8 remains focused specifically on the data required for real-time operations, such as Real-Time Assessments and Operational Planning Analyses. To that end, we recommend the removal of the sub-Requirements R1.5.3 and R2.5.3, as they involve requests for modeling data which do not align with the purpose of TOP-003-8.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

The added sub-requirement 1.5.3 should be removed from this standard as it pertains to data and information collection, not model submissions. This requirement is already addressed in MOD-032-2 R1 (sub-requirement 1.2).

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	No
Document Name	

Comment

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The NAGF supports the comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No

Document Name	
Comment	
Invenergy does not agree with the revisions to IRO-010-5 and TOP-003-8. Specifically, the standards are no longer self-contained and require entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that R1.5.3 of IRO-010-5 and R1.5.3 and R2.5.3 of TOP-003-8 be removed entirely or revised to state, “Requirements for model submissions consistent with MOD-032-2.”	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy does not agree with the revisions to IRO-010-5 and TOP-003-8. Specifically, the standards are no longer self-contained and require entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that R1.5.3 of IRO-010-5 and R1.5.3 and R2.5.3 of TOP-003-8 be removed entirely or revised to state, “Requirements for model submissions consistent with MOD-032-2.”	
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 the opinion of ACES that NERC registered entities should not be subjected to potential violations of multiple NERC Reliability Standards Requirements for a single action. In other words, we contend that by including requirements for model submissions in both MOD-032-2 and in a documented data specification(s), responsible entities will now be subject to a form of double jeopardy (i.e., claim preclusion). ACES recommends only requiring model submissions under MOD-032-2 and subsequently striking the following newly proposed requirement parts: IRO-010-6 Requirement R1 Part 1.5.3, TOP-003-8 Requirement R1 Part 1.5.3, and TOP-003-8 Requirement R2 Part 2.5.3.	
Likes 0	
Dislikes 0	

Response

Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	

California ISO abstains from the response to this question.

Consistent with the response to Q1 above providing a superior alternative to the separate ERO criteria document, the language in IRO-010-6 Requirement R1, Part 1.5.3; TOP-003-8 Requirement R1, Part 1.5.3; and TOP-003-8 Requirement R2, Part 2.5.3 should be changed to read as follows:

"Requirements for model submissions consistent with the model submitted for planning purposes in accordance with MOD-032;"

Referencing MOD-032 instead of a separate ERO criteria document satisfies FERC's directives in Order No. 901 by ensuring consistency between operations models and planning models, while also leveraging model quality and accuracy requirements associated with MOD-032 submissions.

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

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

The TOP-003 data request language for IBR models is concerning. Other models are not asked for so the specificity about IBRs is unusual.

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
For this question, ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
SPP supports the comments filed by the SRC regarding this question.	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	
TXNM Energy feels that RTO (real-time operations) and OPA (operating planning analysis) communication and modelling are two separate actions, and this muddles the two	
Likes 0	
Dislikes 0	

Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports the language as long as its directed towards the appropriate registered entity.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the following comments submitted by EEI on behalf of its members:	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool’s comments.	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC does not have any comments on these proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 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	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 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	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
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	
Greg Sorenson - ReliabilityFirst - 10 - RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
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 supports most of the standard revisions to IRO-010 and TOP-003. However, significant changes to NERC's external document "ERO Approved Criteria for Acceptable Models document" since the last IRO-010 and TOP-003 revisions, specifically the inclusion of criteria modifications that could impact a Registered Entities compliance, highlight our significant concern with the proposed IRO-010 and TOP-003 revisions.

There are simple changes that NERC can make IRO-010 and TOP-003 revisions a success. This includes:

1. Moving any criteria in the "ERO Approved Criteria for Acceptable Models document" within the standard, and converting the external model reference to a "ERO Approved Acceptable Models list" consistent with FERC 901 requirements. Additional comments are included in question 6.
2. TOP-003 R2 should not apply to BAs as they do not use steady state, short circuit, and dynamic modeling data as part of their responsibilities.
3. The following requirement needs to be explicitly added to the standard:
    - "Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the ERO; unless it shall otherwise reduce the viability of the [RC, BA, TOP] ability to perform their analysis functions in a timely manner."
    - In the ERO document, Item #4 must be removed. It is unnecessary, not applicable to operational models, and impractical.
    - In the ERO document, Item #5 must include clarifications similar to previous versions. For example:
        - *"Models shall not reduce the viability of a Registered Entity's ability to perform their OPAs and RTAs in a timely manner. This may require uses of models listed on the Unacceptable Model List provided the model is accompanied by sufficient documentation to explain the parameters, states, and usability of the model to simulate small signal and large disturbance behavior for the scope of responsibility of the NERC Registered Entity."*

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EPRI agrees with the intent of the proposed IRO-010-5 and TOP-003-8 modifications but abstains from answering with "Yes" or "No" to this question.

EPRI research informs the potential need and feasibility of changes to IRO-010-5 and TOP-003-8, see for example the references listed in response to Q1.

Likes 0	

Dislikes 0	
Response	

4. Do you agree with the proposed DER definition? Please refer to the technical rationale, which provides rationale behind the drafting team's intent and previous definitions proposed. If you do not support the definition as proposed, please explain the changes that, if made, would result in your support.

Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	
TXNM agrees with MRO's statement on definition.	
Likes 0	
Dislikes 0	
Response	

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
SPP supports the comments filed by the SRC regarding this question.	
Likes 0	
Dislikes 0	
Response	

Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	
ERCOT abstains from the response to this question. The proposed definition does not explicitly include demand reduction in the DER definition. For a complete definition, this should be more clearly indicated whether it is or is not included.	

Distributed Energy Resources (DER): Generators and energy storage technologies connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an end-use customer that is supplied from a distribution system.	
Likes 0	
Dislikes 0	
Response	
Colten Mitchell - Indiana Municipal Power Agency - 4	
Answer	No
Document Name	
Comment	

No. Both proposed standards (MOD-032-2; MOD-033-3) rely on the proposed DER definition to describe the IBR-DERs that Order 901 directs these standards to address, in aggregate, for purposes of data reporting and modeling. *See, e.g.*, proposed MOD-032-2, R2.2.1 & n.1; proposed MOD-033-3, R1.1.2. A key problem with the proposed use of the DER definition is that it is inconsistent with Order 901's express intent and directives, and therefore will undermine FERC's objectives, described above, to accurately represent IBRs, which is needed because such generation responds differently to system disturbances than synchronous generation.

Although Order 901 expressly directs the development of standards requiring the provision of data and modeling of aggregate IBR-DERs, the proposed draft standards use a generalized DER definition, which includes both IBRs and non-IBR generation. *See, e.g.*, Order 901, PP 7, 53. *See also* MOD-032-2 Technical Rationale Figure 2 (at 5). While the MOD-032-2 Technical Rationale, at 7, found it practical to have a consistent estimation framework for all DERs regardless of technology, the proposed DER definition fails to isolate IBR-DERs so that their impacts can be analyzed and appropriately accounted for in modeling, operations, and planning. The addition of Item 9.c under the "steady-state" column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, but the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards invites confusion that could also carry over to other standards that are intended to account for the particular characteristics of IBRs. For example, Item 10 under "dynamics" of MOD-032-2 Attachment 1 fails to make the distinction captured in Item 9.c. *Compare* Order 901, PP 37-39, 50-56. MOD-033-3 footnote 1 likewise refers to the DER definition without focusing on those DERs that are IBRs.

Thus, the proposed homogenized DER definition may impede the ability of these standards, and other IBR-related standards, to achieve Order 901's reliability objectives. Steps should be taken to more clearly define IBR-DERs or otherwise further mitigate the potential adverse impacts of use of the proposed DER definition.

Context for and a summary of all concerns with proposed MOD-032-2 are provided in Question 1; further concerns with regard to the unregistered IBR definition are provided in Question 7.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	

Comment
ITC recommends adding the following in **bold**, and removing the following in *italics*: Distributed Energy Resources (DER): ITC proposes the following change to the DER definition to add more clarity regarding the IBR connected to a distribution system "Generators, **and IBR** *energy storage technologies* connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an end-use customer that is supplied from a distribution system".

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	

Comment
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	

Comment
ATC is of the opinion that the DER definition should be modified as suggested below: **Distributed Energy Resources (DER):** Generators and energy storage technologies connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System**,** including those connected behind the meter of an end-use customer that is supplied from a distribution system**, based on the MVA threshold defined by the Planning Coordinator.**

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Distributed Energy Resources (DER): propose the following change to DER definition add more clarity regarding the IBR connected to a distribution system “Generators, and IBR connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an enduse customer that is supplied from a distribution system”.	
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; Kris Kirkegaard, 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 provided by Tacoma Power on the DER definition.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
No. Both proposed standards (MOD-032-2; MOD-033-3) rely on the proposed DER definition to describe the IBR-DERs that Order 901 directs these standards to address, in aggregate, for purposes of data reporting and modeling. *See, e.g.*, proposed MOD-032-2, R2.2.1 & n.1; proposed MOD-033-3, R1.1.2. A key problem with the proposed use of the DER definition is that it is inconsistent with Order 901’s express intent and directives, and therefore will undermine FERC’s objectives, described above, to accurately represent IBRs, which is needed because such generation responds differently to system disturbances than synchronous generation.	

Although Order 901 expressly directs the development of standards requiring the provision of data and modeling of aggregate IBR-DERs, the proposed draft standards use a generalized DER definition, which includes both IBRs and non-IBR generation. *See, e.g.*, Order 901, PP 7, 53. *See also* MOD-032-2 Technical Rationale Figure 2 (at 5). While the MOD-032-2 Technical Rationale, at 7, found it practical to have a consistent estimation framework for all DERs regardless of technology, the proposed DER definition fails to isolate IBR-DERs so that their impacts can be analyzed and appropriately accounted for in modeling, operations, and planning. The addition of Item 9.c under the "steady-state" column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, but the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards invites confusion that could also carry over to other standards that are intended to account for the particular characteristics of IBRs. For example, Item 10 under "dynamics" of MOD-032-2 Attachment 1 fails to make the distinction captured in Item 9.c. *Compare* Order 901, PP 37-39, 50-56. MOD-033-3 footnote 1 likewise refers to the DER definition without focusing on those DERs that are IBRs.

Thus, the proposed homogenized DER definition may impede the ability of these standards, and other IBR-related standards, to achieve Order 901's reliability objectives. Steps should be taken to more clearly define IBR-DERs or otherwise further mitigate the potential adverse impacts of use of the proposed DER definition.

Context for and a summary of all concerns with proposed MOD-032-2 are provided in Question 1; further concerns with regard to the unregistered IBR definition are provided in Question 7.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

Oncor Electric Delivery Company LLC ("Oncor") considers the "Distributed Energy Resource" ("DER") definition used in the Technical Rationale for Reliability Standard MOD-032-2 too vague because it does not contain a voltage class threshold for an energy resource to be considered a DER.

Oncor's view of DER is consistent with ERCOT's definition of DER, which is: "An electrical generating facility consisting of one or more on-site distributed generation units connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system." This definition can be found here: https://www.ercot.com/files/docs/2017/03/24/DER_OnePager_FINAL.pdf

From Oncor's experience, the total capacity of the installation's on-site distributed generation units, a type of distributed energy resource, may exceed ten megawatts (MW).

Is there any MW size threshold for Generator and energy storage technologies to be taken into account when the end-use customer is served at transmission voltage? Oncor would prefer a MW size threshold be specified in the definition.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO

Answer	No
Document Name	
Comment	
Distributed Energy Resources (DER): MRO NSRF propose the following change to DER definition add more clarity regarding the IBR connected to a distribution system “Generators, and IBR energy connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an enduse customer that is supplied from a distribution system”.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
AES Indiana supports comments provided by EEI.	
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) feedback.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No

Document Name	
Comment	
MH proposes the following change to DER definition add more clarity regarding the IBR connected to a distribution system “Generators, and IBR connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an enduse customer that is supplied from a distribution system”.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
DER should not be defined specifically inside of a NERC standard. This needs to be accomplished in the Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The definition of DER does not include any size requirements, such as voltage or MVA, that specifies when an individual DER or aggregate DER falls under the purview of the standard. TVA recommends adding size requirements to the definition or in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	

Answer	No
Document Name	
Comment	

Entergy is concerned that the clause "*behind the meter of an end-use customer that is supplied from a distribution system*." will require modeling legacy industrial generation behind the meter on distribution where data is not available because of the age of the units, whereas much larger industrial generation behind the meter on the transmission system is not required to be modeled. Entergy has concerns that it will not be practical to model all unregistered DER facilities on the Distribution system without some type of DER unit/system MW threshold or aggregated generation MW threshold.

Likes 1	Scott Brame, N/A, Brame Scott
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; John Nierenberg, 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 requests clarity from the SDT as to whether the changes to MOD-032-2 apply to small generation plants connected to the transmission system. The proposed DER definition does not include a threshold or criteria for what is considered "distribution". As a result of not defining this threshold, there is confusion as to what could be considered DER generation. For example, Tacoma Power owns a 4 MW hydro plant connected at 115 kV. Tacoma Power recommends adding clarity in the technical rationale as to whether this revision applies to non-BES synchronous generation connected to the transmission system.

If the intent of the SDT is to include an aggregate of all generating resources in MOD-032-2, then Tacoma Power proposes replacing the word "distribution" with the word "power" in the DER definition. This change would clarify that any non-BES generation must be included within interconnection models, regardless of whether it is connected to transmission or distribution. Alternatively, the SDT could describe in the technical rationale how non-BES synchronous resources connected to the transmission system should be handled under MOD-032.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	
Comment	

AES adopts EEI's comments regarding the proposed DER definition.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
For this question, ERCOT does not join the comments submitted by the IRC SRC.	
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

James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

However, the proposed term is not clear enough. Does it intend to call a 15MVa generator connected at 60 kV a DER? Or since it is connected at 60 kV, it is considered a non-BES, unregistered Transmission Line-connected generator and therefore, not covered by the definition? It appears that the SDT has structured the requirement to have two different terms that must be used in tandem to ensure all desired resources are addressed. This could lead to the potential for missing entities in future standards that only use the DER definition without the unregistered IBR Resources.

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 EEI's comments.

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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports 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 has no objections to the proposed definition for DER.
Likes 0	
Dislikes 0	
Response
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.
Answer	Yes
Document Name	
Comment
Portland General Electric (PGE) supports the Western Power Pool’s comments.
Likes 0	
Dislikes 0	
Response
Marcus Bortman - APS - Arizona Public Service Co. - 6
Answer	Yes
Document Name	
Comment
None
Likes 0	
Dislikes 0	
Response

Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Nextera supports comments provided by EEI	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no issues with the Definition.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
The STD has come up with reasonable definition for DERs, however the use of the abbreviation is very limited to The Technical Document and MOD-032, Attachment 1. Rather than adding a definition to the NERC Glossary, perhaps the definition would be better as an addition to the footnotes for Attachment 1 and a definition paragraph in the Technical Document.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emma Halilovic - Hydro One Networks, Inc. - 1	
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	
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	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	

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	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joseph Scott - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
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	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	
Response	

Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
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	

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 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	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
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	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EPRI agrees with the intent of the proposed DER definition but abstains from answering with "Yes" or "No" to this question. We note that the SDT considered existing definitions from NERC SPIDERWG & DERTF, IEEE 1547-2018, FERC, CPUC, NYISO, and decided to not align their proposed DER definition with any of these existing definitions.

EPRI research informs the potential need and feasibility of changes to IRO-010-5 and TOP-003-8, see for example the references listed in response to Q1.

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 agrees with the definition as proposed.

Likes 0	
Dislikes 0	

Response

5. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-5, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes the resources required is only cost effective if the modeling data estimation is useful and backed by actual data. BPA does not support an uninformed modeling data and parameters estimation, as it has no reliability benefit.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

Until response and/or clarification of comments are made by the DT, FirstEnergy cannot determine if these standards can be met in a cost-effective manner.

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; John Nierenberg, 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 agrees that the proposed MOD-032-2 and IRO-010-5 Standards are cost effective. However, Tacoma Power does not agree that the new TOP-003-8 sub-Requirements R1.5.3 and R2.5.3 are cost effective. TOP-003-8 R2.5.3 is redundant to MOD-032-2 R2. The BA collects the relevant modeling data for the Criteria for Acceptable Models guidance via MOD-032-2 R2. It is not cost effective to perform duplicative work.

Additionally, the TOP does not have a role in requesting modeling data in the current TOP-003-8. It is not cost effective to require the TOP to collect modeling data under TOP-003-8 R1.5.3. This scope of work should be added to MOD-032-2, if the intent of the SDT is to require the TOP to request modeling submissions.	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	No
Document Name	
Comment	
Item 25 in the SAR states that a uniform framework among the three standards must be created, and these changes do not accomplish that.	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD agrees that the proposed MOD-032-2 and IRO-010-5 Standards are cost effective. However, CHPD does not agree that the new TOP-003-8 sub-Requirements R1.5.3 and R2.5.3 are cost effective. TOP-003-8 R2.5.3 is redundant to MOD-032-2 R2. The BA collects the relevant modeling data for the Criteria for Acceptable Models guidance via MOD-032-2 R2. It is not cost effective to perform duplicative work.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

TVA believes that the costs associated with gathering unregistered IBR and aggregate DER data, which will undoubtedly consist of a large percentage of estimated data, do not prove cost-effective as the result may negatively affect model accuracy and provide little, to no, reliability benefit. We also expect there will be unforeseen costs associated with this effort.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5

Answer	No
Document Name	

Comment

For MOD-32 it is a heavy lift for the DP to provide the additional data requested. Even if an estimate is utilized it takes time to document the methods used for the estimate. Additional time to implement the changes and a gradual approach (i.e prioritizing larger size DER's) could be an approach.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation abstains from this question as it does not have IBR/DER resources.

Likes 0	
Dislikes 0	

Response

Zenon O'young-Chu - Seattle City Light - 3

Answer	No
Document Name	

Comment

Support BPA's comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Since the TO has no ability to force unregistered entities to provide necessary data, delays in modeling are possible, even with a TO's established estimation methodology. The cost will be affected by the time and additional effort needed by the TO to coordinate with unregistered entities.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE believes the resources required are only cost effective if the modeling data estimation is useful and backed by actual data. CEHE does not support an uninformed modeling data and parameters estimation, as the TO is not the appropriate registered entity to be responsible for providing estimations of unregistered load.	
Likes 0	
Dislikes 0	
Response	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	
Comment	

SIGE does not agree that it addresses the scope in a cost-effective manner. The modifications put a burden on TO's to purchase additional software. There is no easy way to dynamically model; need more defined criteria.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	No
Document Name	

Comment

No. As discussed in detail in Questions 1, 4, and 7, the proposed modifications do not effectively address Order 901's directives; as they are not effective, they cannot be cost-effective.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

The ambiguity potential in Section 2.1 could create a cost burdening requests from Regional Entities.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

The ambiguity potential in Section 2.1 could create a cost burdening requests from Regional Entities

Alison Mackellar on behalf of Constellation Segments 5 and 6

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; Kris Kirkegaard, 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 provided by Tacoma Power.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez

Answer	No
Document Name	

Comment

SRP supports comments provided by Bonneville Power.

Likes 0	
Dislikes 0	

Response

James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment	
The MOD-032 standard continues to expect all other entities to track the needs of the TP and PC rather than having the TP and PC actually ask entities for data they want. This is extremely inefficient for newly registered GOs/GOPs and will likely lead to even larger issues with the registration of entities not connected to the companies that are registered as TPs and PCs.	
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	
Please see our comments regarding questions 1 and 3.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
More clarity is needed with regards to final data responsibility.	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	

TXNM would have to perform a cost analysis and standard impact assessment to know the true cost of these standards as with the increase of responsibility that a TO would take on for these standard modifications.

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	Yes
Document Name	

Comment

Portland General Electric (PGE) supports the Western Power Pool’s comments.

Likes 0	

Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
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	
Nazra Gladu - Manitoba Hydro - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
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	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
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	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
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	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	
Comment	
Support BPA Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	

SCL supports BPA's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	
Question not applicable for MRO	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
The proposed revisions involve a wide range of modeling variances leading to significant costs and time. Additionally, implementation costs analysis becomes challenging also due to insufficient clarity at this time on Acceptable Models (currently there is a list of Unacceptable Models that may be enforceable). Currently, PCs and TPs have limited ability to collect data from non-registered entities. There does not seem to be a reliability benefit that could be realized before additional mechanisms to collect adequate modeling data on all DERs (including non-registered IBRs and other DER entities), including additional or revised mandatory requirements to provide sufficiently accurate data to TPs and PCs become enforceable	
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	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
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's primary focus is on electrical system reliability and will not provide a response to this question.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

No comment

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

ATC does not have a comment on the cost effectiveness of these modifications.

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 will not comment on the cost effectiveness of the project.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Invenergy is unable to comment on the cost effectiveness of the revisions.

Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Invenergy is unable to comment on the cost effectiveness of the revisions.	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EPRI agrees with the intent of the proposed reliability standards but has not analyzed their cost-effectiveness. Hence, we abstain from answering with "Yes" or "No" to this question.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the proposed ERO Approved Criteria for Acceptable Models document? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC

Answer	No
Document Name	

Comment

Regarding the aggregated DER dynamic model, NERC should define a methodology that utilities can follow to derive such an aggregated DER dynamic model before the change is implemented. The methodology must be practical and easy to follow.

Likes 0	
Dislikes 0	

Response

Greg Sorenson - ReliabilityFirst - 10 - RF

Answer	No
Document Name	

Comment

The document does not seem to be written to address both equipment specific and aggregate models. In fact, it seems like the concept of modeling an aggregate IBR-DER or even aggregate dynamic loads may contradict Item #1 under "Usability Requirements"...1) A model manual, or other documentation, with a description of all model parameters, variables, and states. The manual or other documentation shall also describe the range of validity of the model and valid use cases or studies for which the model has sufficient fidelity.

Likes 0	
Dislikes 0	

Response

Emma Halilovic - Hydro One Networks, Inc. - 1

Answer	No
Document Name	

Comment

Regarding the aggregated DER dynamic model, NERC should define a methodology that utilities can follow to derive such an aggregated DER dynamic model before the change is implemented. The methodology must be practical and easy to follow.

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

For this question, ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	No
Document Name	

Comment

SPP supports the comments filed by the SRC regarding this question.

Likes 0	
Dislikes 0	
Response	
Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	
Please see the IRC SRC's response to question 1.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy recommends that the proposed "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2, rather than separately maintained.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy recommends that the proposed "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2, rather than separately maintained.	
Likes 0	

Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The proposed ERO Approved Criteria for Acceptable Models document suggests that the plant may require two sets of models: operational models and planning models. FERC Order 901 P141 directs NERC to mandate that generator owners of registered IBRs and transmission owners with unregistered IBRs on their system provide Bulk-Power System planners and operators (including planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) with dynamic models that accurately represent the dynamic performance of both registered and unregistered IBRs. This directive appears to aim at ensuring the availability of dynamic models that accurately reflect performance for use in planning and operational studies.	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO’s NERC Standards Review Forum’s (NSRF) feedback.	

Likes 0	
Dislikes 0	
Response	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The NAGF supports the comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC agrees that NERC is responsible for the NERC-Approved Model Library and the associated processes that go along with both maintaining and updating that library. However, we do not agree that Model Criteria should be maintained and modified outside of the Approved Reliability Standards. Model Criteria should not be a moving target. For this reason, we believe that the Model Criteria should be included in the affected Reliability Standards and only changed when those Standards are modified. To address our concerns, we ask that the model criteria be removed from this document and	

rewrite the document to focus on both the Approved and Unapproved Model Library and associated processes for updating and approving models for industry use.

The ERO Approved Criteria for Acceptable Models document should also make clear and define in the document that it applies to generator models, not system models.

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 ERO document goes beyond an Acceptable Model List and includes criteria that must be included in NERC standards. This is in violation of NERC standard development guidance, FERC 901 requirements, and bypasses the NERC Rules of Procedure for future modifications that can impact entities' compliance with the affected NERC standards.

- In order to comply with the NERC's Acceptance Criteria of a Reliability Standard Item #6 Completeness, "Each Reliability Standard should be complete and self-contained. A standard should not depend on external information to determine the required level of performance." As proposed, the revised standards do not conform to this requirement.
  - The "Criteria for Acceptable Models maintained by the ERO" goes well beyond a library of models as specified by FERC 901, but instead includes compliance criteria for use, interpretation, and adherence of these models.
  - This is of significant concern, as an entity's compliance would become dependent on an external set of criteria not vetted through the NERC standard process.
  - Furthermore, the approval process for changes to the document – which could cause an entity to become non-compliant – would not be subject to NERC standard modifications (essentially bypassing NERC ROP).
- FERC 901 requirements that specify the development of new standards and using the ***standard development process*** to refer to a model library – not an external set of criteria. Therefore, the "Criteria for Acceptable Models maintained by the ERO" should be replaced with a version that is solely focused on a library list of acceptable models.
  - P122 "direct NERC to develop new or modified reliability standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady-state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models"
  - P124 "direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamic studies" [as proposed, it is outside the ***standards development process*** with a separate ERO/RSTC process]
  - P125 "direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models"
- Southern Company acknowledges there is a desire to be agile with the Library – but this agility should not bypass NERC Rules of Procedure
  - If the Acceptable Models truly becomes a library only list, it can include a process by which models can be ***added*** to the list by the ERO and RSTC, but models should not be removed from the list without going through the full industry standard review process as it could significantly modify an entities compliance. Alternatively, a clear implementation schedule not to be less than 2+ years for the removal of any model could be established.
  - If there are critical criteria that must be adhered to from a compliance perspective, these should be incorporated into the specific standards as requirements – not within an external document.

        - For example, it is imperative the RC and TOP retain the flexibility to utilize models needed to meet its OPA and RTA requirements – both for timing, accuracy, and availability. This may require utilizing models that have been reviewed and verified by the entity to perform accurate representation within those operational assessment constraints (e.g., different for remote external areas afar from the scope of responsibility that accurately simulate dynamic response). These criteria and recognition should be embedded in the standard, not an external document.
        - The acceptability criteria for allowance and submission of user-written models should be clear, including coordination for use across interconnection-wide cases.
- The revised NERC Acceptable Models list needs to ensure there are appropriate exceptions, particularly for modeling of neighboring utilities in remote external areas. Specifically:
    - Exceptions must be granted for use of models on the Unacceptable list if the annual NERC MMWG dynamics data library contains these models, since no other source exists for most entities to procure dynamics data for systems beyond their own boundaries.
    - Additionally, for operational models that must meet availability and timing requirements to perform operational-related assessments - constraints that long-term planning analyses do not face – there needs to be accommodations for remote external area modeling outside the scope of the BA, TOP, and RC footprint. For example, the GENCLS model is introduced by the DYNRED program into appropriate system equivalent models which have been verified to accurately represent the dynamic behavior of external generation beyond Tier 1 neighbors of an RC and TOP. This model represents the dynamic behavior of the coherent group as if it were a single generator – substantially reducing computer run-time while maintaining all necessary accuracy. Such models must be allowed by the RC and TOP when determined by the RC or TOP to accurately model to simulate small signal and large disturbance behavior for the scope of responsibility of the NERC Registered Entity.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Attachment 1 requests data that requires collection of data from OEM's which can be overly burdensome and not possible due to many historical manufacturers no longer in business, thus making the information extremely difficult to obtain.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	No
Document Name	

Comment

Attachment 1 requests data that requires collection of data from OEM's which can be overly burdensome and not possible due to many historical manufacturers no longer in business, thus making the information extremely difficult to obtain.

Kimberly Turco on behalf of Constellation Segments 5 and 6

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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.

Likes 0	
Dislikes 0	

Response

Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion

Answer	No

Document Name	
Comment	
Dominion Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	
Comment	
SIGE supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not support or see a need for the proposed document titled ERO Approved Criteria for Acceptable Models for the reasons provided below. However, we do support the continued use of the NERC document titled “Dynamic Modeling Recommendations”, which we believe provides useful guidance to the industry while also containing the Unacceptable Model list. This document would also provide a familiar reference document for the Industry that could be relied upon to provide clarity on unacceptable models and a trusted source of useful recommendations to planners.

1. FERC Order 901 directives clearly “require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities’ respective planning and operation models and to build interconnection-wide models.” (see FERC Order 901, P125). While the proposed document does not identify any approved component generic library models to be used when creating interconnection-wide system models.

2. Planning software used by PC and TPs already utilize generic library models that are widely and consistently available through industry planning software, negating the need for NERC to do anything relative to the development of an approved component generic library model list beyond maintaining the existing NERC Unacceptable Model list.

3. We additionally disagree that model criteria should be contained in a standalone document outside of approved Reliability Standards. However, we agree with FERC that model criteria should be uniformly established and shared by PCs, TPs, RCs, TOPs and BAs through the enforceable Requirements contained in the Reliability Standards for each interconnection. (See FERC Order 901, P161)

4. Moreover, the document contains language within the proposed criteria that is far too ambiguous to be enforceable or auditable within a NERC Reliability Standard. (For example: “negligible error(s)”, “sufficient fidelity”, “robustly initialize”, “reasonable initial conditions”, or “simulation solution challenges”.)

5. We also do not agree that the “Usability Requirements” that cite “simulation crashes” or “solution challenges” as justifications for deeming a model unacceptable. While in some cases, this may be justification for deeming a model unacceptable, such events can be caused by other factors beyond the model and therefore such an arbitrary determination without consideration of other factors may disqualify the best or in some case the only available model.

For these reasons, we ask that the proposed document be abandoned because it provides no useful direction to planners and modelers as originally intended.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO

Answer	No
Document Name	

Comment

The proposed ERO Approved Criteria for Acceptable Models document suggests that the plant may require two sets of models: operational models and planning models. FERC Order 901 P141 directs NERC to mandate that generator owners of registered IBRs and transmission owners with unregistered IBRs on their system provide Bulk-Power System planners and operators (including planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) with dynamic models that accurately represent the dynamic performance of both

registered and unregistered IBRs. This directive appears to aim at ensuring the availability of dynamic models that accurately reflect performance for use in planning and operational studies.

Could you please clarify whether we are expected to provide both an operational model and a planning model?

Likes 0	
Dislikes 0	

Response

Sing Tay - AES - Indianapolis Power and Light Co. - 3

Answer	No
Document Name	

Comment

AES Indiana supports comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power supports EEI’s feedback.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

The proposed ERO Approved Criteria for Acceptable Models document suggests that the plant may require two sets of models: operational models and planning models. FERC Order 901 P141 directs NERC to mandate that generator owners of registered IBRs and transmission owners with unregistered IBRs on their system provide Bulk-Power System planners and operators (including planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) with dynamic models that accurately represent the dynamic performance of both registered and unregistered IBRs. This directive appears to aim at ensuring the availability of dynamic models that accurately reflect performance for use in planning and operational studies.

Could you please clarify whether we are expected to provide both an operational dynamic model(s) and a planning model(s)? Additionally, we recommend changing the name to “ERO Approved Criteria for Acceptable Dynamic Models,” as the term "Model" could also refer to steady-state and short circuit models.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

Nextera supports comments provided by EEI

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 EEI.

Likes 0	
Dislikes 0	

Response

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6

Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with EEI's conclusion that the "ERO Approved Criteria for Acceptable Models" document may not align with FERC order 901 directives. We agree this document could be responsible for the Model Library and processes needed to submit proposed additions, however the model criteria should be controlled through enforceable requirements within each Reliability Standard.

Black Hills Corporation also agrees with EEI's comments about the ambiguous language and lack of an Accepted Models list. Also, that the citing of "simulation crashes" or "Solution challenges" may result in a model being deemed unacceptable due to outside factors, even if it is the best or possibly only model available.

Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	

The ERO Criteria for Acceptable Models did not go through any standard process and therefore does not have industry consensus.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

R1 reference the ERO maintained Approved Criteria for Acceptable Models. However, this document is not part of the Standard and may pose compliance challenges if updated outside of the Standard Development Process. The process to maintain the list of models (e.g. Unacceptable Model List) relies on NERC determination of the effective date of a change.

For example, if the ERO added a new model to the List of Unacceptable Models in the ERO maintained document without allowing for an adequate implementation timeline, entities may be in noncompliance on the effective date of the revised ERO document.

As drafted the Approved Criteria for Acceptable Models is not clear how and by whom the determination on models that may be acceptable for Planning but not acceptable for Operations is made and documented. It would also be helpful if the Unacceptable Model List includes another column to differentiate between models appropriate for Planning purposes but not appropriate for Operational purposes.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

The ERO Criteria for Acceptable Models does not have industry consensus and was not established through the standards process. TVA does not believe it should be referenced in a compliance standard. In its place, TVA recommends specifications for standard models (where appropriate and available), user-written models (where appropriate and with adequate documentation), and other models (when no alternative is available and requiring justification for use).

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	No
Document Name	

Comment

AES adopts EEI’s comments for the proposed ERO Approved Criteria for Acceptable Models document.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy supports EEI comments which state:

EEI does not support the document titled ERO Approved Criteria for Acceptable Models because it appears that it does not align with FERC Order 901 directives which “require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities’ respective planning and operation models and to build interconnection-wide models.” (see FERC Order 901, P125) While we recognize that the FERC Order 901 may be too restrictive and agree some use of user-defined models is needed, it remains unclear whether NERC has obtained FERC approval to deviate from the Order. Moreover, while we support some use of user-defined models, that usage should be limited and validated across each interconnection with clear enforceable requirements that limit the use of user-defined models except when such usage has been coordination between responsible entities across each interconnection. In addition to this core concern, we offer the following additional comments and concerns with this document below:

1. EEI supports the ERO plan to be responsible for the Model Library and the processes needed for responsible entities to submit for approval proposed additions to that library. We do not agree that this document should contain the model criteria itself. While the model library will be a dynamic document, the model criteria should not be dynamic and is most effectively controlled through enforceable requirements within each Reliability Standard.

2. While this document contains a list of Unacceptable Models, it fails to identify any Acceptable Models for use in Interconnection-wide models as required in FERC Order 901.

3.We are also concerned that the document contains language within the proposed criteria that is far to ambiguous to be enforceable or auditable within a NERC Reliability Standard. (For example: “negligible error(s)”, “sufficient fidelity”, “robustly initialize”, “reasonable initial conditions”, or “simulation solution challenges”.)

4.EEI does not agree that the “Usability Requirements” that cite “simulation crashes” or “solution challenges” as justifications for deeming a model unacceptable. While in some cases, this may be justification for deeming a model unacceptable, such events can be caused by other factors beyond the model and therefore such an arbitrary determination without consideration of other factors may disqualify the best or in some case the only available model

Likes 0	
Dislikes 0	

Response

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	Yes

Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 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	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
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	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
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; Kris Kirkegaard, 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

Joseph Scott - 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	
Carver Powers - Utility Services, Inc. - 4	
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; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	
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	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
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	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
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; John Nierenberg, 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	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EPRI agrees with the intent of the proposed ERO Approved Criteria for Acceptable Models but abstains from answering with "Yes" or "No" to this question.

We share the following observations with the SDT for consideration in future drafts:

–The new terms for the NERC Glossary of Terms proposed by Project 2020-06 for MOD 026/027 etc., i.e., “model validation” and “model verification” are not used in the Criteria for Acceptable Models document.

–In addition to “expected or as-built facilities”, consider adding "as-left" or "as-configured”

–Consider distinguishing between “parameter names” and “parameter values”

–Are standardized tests for “model validation” defined somewhere?

–Consider adding requirements to explicitly document known use cases for which a model shall *not* be used

–Consider changing the term “initial value” to “default value”

–Add a requirement that triggers more thorough model validation whenever models are provided with “default values”

–The term “model adequacy” is used but not defined in the NERC Glossary of Terms as of Feb 26, 2025.

–How would the “explanation of the model’s adequacy” look like? Could it be a "model validation report" for equipment-level models and a "model verification report" for plant-level models, similar to the procedures proposed in IEEE P2800.2 which is currently open for SA initial ballot and public review at https://publicreview.standards.ieee.org/public-review-web/public-app

–Consider clarifying whether "a list of commonly tuned parameters" refers to "parameter values" that are site-specific or the subset of "parameter names" that shall be used to tuned the model to site-specific settings.

–Consider correcting a reference given that Table 1 is now "above".

Likes 0	
Dislikes 0	

Response

Scott Thompson - TXNM Energy - 3

Answer	
Document Name	

Comment

The criteria seems vague and usability requirements are not specific, please clarify what would be usable and what would unusable.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	
Comment	
Reclamation abstains from this question as it does not have IBR/DER resources.	
Likes 0	
Dislikes 0	
Response	

7. Provide any additional comments for the drafting team to consider, if desired.	
Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
We appreciate the time and effort put forward by the SDT to resolve FERC's Order 901 directives. It is a difficult job and we feel the SDT has done a good job balancing the interests the industry and FERC.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA appreciates the opportunity to respond to this posting. The areas where BPA supports the intent of these revisions is based upon requiring the proper *registered* entity to provide the data.	
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	

Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	

For the implementation plan for MOD-032-2, AES does not agree with the proposed 12 month time frame after the effective date for MOD-032-2 for requirements R2-R4.

Some TPs and PCs may elect to postpone development and publishing of their revised data requirements and reporting procedures until the end of the two-year implementation period for the standard leaving only the 12-month time frame to respond. AES has over 400 unregistered IBRs and DERs in which model information should be provided to the responsible entity. While it could be said that unregistered IBRs and DERs are not required to comply with the standard, it is AES's responsibility to help ensure reliability and provide the requested information in the intended manner. With limited modeling resources, AES requests a longer implementation plan for R2-R4 of at least 24 calendar months following the effective date of the standard.

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; John Nierenberg, 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 is concerned that the term "unregistered IBR" is not well understood in the industry. Without a formal definition in the Glossary of Terms, it will be difficult for entities to look up the scope of resources that fall under this currently undefined category. Additionally, the term "unregistered IBR" will be used in potentially several Standards, so it would be more efficient to have this term formally defined in the glossary. Defining this term in a footnote of several Standards opens the possibility of the definition being inconsistent between Standards, and would require revising multiple Standards if the definition needs to be updated in the future. In order to ensure efficiency and make it easier to lookup the definition, Tacoma Power recommends using the definition in the MOD-032 footnote to create a NERC glossary definition for Unregistered IBR.

Tacoma Power proposes separate implementation phased dates for MOD-032 compliance for Steady-State versus Dynamics data. The proposed timeline in the implementation plan appears adequate for entering the steady-state data into the interconnection model. The timeline for modeling aggregated DER dynamics data should be extended by an additional 12 months. The modeling tools and base case building process within WECC does not currently have the capability to include multiple different IBR resources within the composite load model. In order to accommodate data for several different IBRs types connected to a single substation transformer, there will need to be extensive collaboration between utilities within WECC. There will also need to be updates by power flow software vendors to implement new composite load models that call for multiple IBR types within a single composite load model. The proposed timeline is vastly too short for WECC utilities to reach agreement on the updates to the WECC Data Preparation Manual, much less for software developers to be able to provide adequate software implementation once the new requirements are defined.

Likes 0	

Dislikes 0	

Response

Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	

Comment
Seattle City Light has concerns regarding the proposed implementation timeline for modeling dynamic data for Distributed Energy Resources (DER). While the timeline for steady-state DER modeling appears reasonable, dynamic model data for many existing DERs and inverter-based resources (IBRs) is currently unavailable. Additionally, if it is determined that multiple types of IBRs are served by the same substation, utilities like Seattle City Light must ensure that their power system analysis software can accommodate this complexity. Given these challenges, Seattle City Light requests additional time to implement dynamic modeling, particularly for unregistered IBRs. The term “Unregistered IBR” is not clearly defined in the current revision of the standard. Seattle City Light recommends that a formal definition be added to the NERC Glossary of Terms to promote consistent understanding and interpretation across all applicable entities. Additional Comments – Support TPU Comments re: TOP-003-8

Likes 0	
Dislikes 0	

Response

Robert Jones - Seattle City Light - 4	
Answer	
Document Name	

Comment
· Seattle City Light has concerns regarding the proposed implementation timeline for modeling dynamic data for Distributed Energy Resources (DER). While the timeline for steady-state DER modeling appears reasonable, dynamic model data for many existing DERs and inverter-based resources (IBRs) is currently unavailable. Additionally, if it is determined that multiple types of IBRs are served by the same substation, utilities like Seattle City Light must ensure that their power system analysis software can accommodate this complexity. Given these challenges, Seattle City Light requests additional time to implement dynamic modeling, particularly for unregistered IBRs.

· The term “Unregistered IBR” is not clearly defined in the current revision of the standard. Seattle City Light recommends that a formal definition be added to the NERC Glossary of Terms to promote consistent understanding and interpretation across all applicable entities.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
TVA appreciates the efforts by the standard draft team. In addition to the comments provided above, TVA believes that an effort of this magnitude in acquiring model data for unregistered IBRs and aggregate DERs will likely take considerable time and iterations. The implementation plan only allows 12 months after the effective date of the Reliability Standard. That is not sufficient time to attempt to acquire modeling data and parameters, fail to do so, and then develop estimated values with technical justifications. TVA recommends extending the implementation of R2, R3, and R4 to 36 months.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	
Comment	
We would want to inquire how power limited and inadvertant export capabilities would be captured. For example if the aggregate DER was 5 MW but 4 MW was power limited it implies that we would need to do gross load and name plate of DER, but how would power controlled systems be reported, especially for dynamic behavior where most distribution or rooftop systems may inadvertanekty export for up to 30 seconds or create load swings for that period of time	
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	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	
Document Name	
Comment	
Black Hills Corporation does not agree with the Implementation Plan because the “ERO Approved Criteria for Acceptable Models” document may not align with FERC order 901 directives. We agree this document could be responsible for the Model Library and processes needed to submit proposed additions, however the model criteria should be controlled through enforceable requirements within each Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
(1) Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)). (2) In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement? (3) TOP-003 and IRO-010 standards pertain to the data specification and exchange requirements for Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Time Horizons for requirements within MOD-032-2 [Long-Term Planning] and TOP-003-8/IRO-010-7 [Operations Planning] should align with each other. Models created in MOD-032-2 will be utilized for Operations Planning and Real-time Assessments. As such, data exchange requirements in the form of “model submissions” should reflect all valid time frames, including entities that need to receive this data as part of their required assessments. (4) Attachment 1, Column #2 (item 7(a)) IBR behaviors [remove "capabilities"] related to momentary cessation, tripping, Ride-through, and frequency control	

(5) Attachment 1, Column #2 (items 7(a) and 10(a)). Although there are provisions for representing voltage and frequency protection settings in positive sequence simulations, the terms “momentary cessation, tripping, and ride-through” are too ambiguous. These concepts may not be fully representable in positive sequence phasor domain simulations and lack the necessary clarity to ensure compliance.

(6) Attachment 1, Column #2, Item 10: The MRO NRFS recommends establishing a MW threshold level for requiring unregistered IBRs, as determined by the Planning Coordinator (PC) and Transmission Planner (TP) in R1. Additionally, due to the lack of standardized distribution DER performance requirements, accurately representing the behaviors of unregistered Aggregate Distributed Energy Resources (DER) in sections 10(a) and 10(b) may be challenging. We recommend including “estimated, assumed, or typical DER behaviors related to momentary cessation, tripping, ride-through, voltage control, frequency control, and voltage and frequency protection settings.”

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

In MOD-032-2 Attachment 1, Data Reporting Requirements, item #10 under steady-state requirements (see below) should be removed. It is an open and unrestricted invitation to request data which has no practical value in assessing transmission system performance. As a result, time and resources will be wasted for no benefit.

"10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]"

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	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	
Document Name	
Comment	

N/A

Seattle City Light has concerns regarding the proposed implementation timeline for modeling dynamic data for Distributed Energy Resources (DER). While the timeline for steady-state DER modeling appears reasonable, dynamic model data for many existing DERs and inverter-based resources (IBRs) is currently unavailable. Additionally, if it is determined that multiple types of IBRs are served by the same substation, utilities like Seattle City Light must ensure that their power system analysis software can accommodate this complexity. Given these challenges, Seattle City Light requests additional time to implement dynamic modeling, particularly for unregistered IBRs.

The term “Unregistered IBR” is not clearly defined in the current revision of the standard. Seattle City Light recommends that a formal definition be added to the NERC Glossary of Terms to promote consistent understanding and interpretation across all applicable entities.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	
Document Name	
Comment	

1. Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)).

2. In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement?

3. TOP-003 and IRO-010 standards pertain to the data specification and exchange requirements for Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Time Horizons for requirements within MOD-032-2 [Long-Term Planning] and TOP-003-8/IRO-010-7 [Operations Planning] should align with each other. Models created in MOD-032-2 will be utilized for Operations Planning and Real-time Assessments. As such, data exchange requirements in the form of “model submissions” should reflect all valid time frames, including entities that need to receive this data as part of their required assessments.

4. Attachment 1, Column #2 (item 7(a)) IBR behaviors capabilities related to momentary cessation, tripping, Ride-through, and frequency control

5. Attachment 1, Column #2 (items 7(a) and 10(a)). Although there are provisions for representing voltage and frequency protection settings in positive sequence simulations, the terms “momentary cessation, tripping, and ride-through” are too ambiguous. These concepts may not be fully representable in positive sequence phasor domain simulations and lack the necessary clarity to ensure compliance.

6. Attachment 1, Column #2, Item 10: The MRO NSRF recommends establishing a MW threshold level for requiring unregistered IBRs, as determined by the Planning Coordinator (PC) and Transmission Planner (TP) in R1. Additionally, due to the lack of standardized distribution DER performance requirements, accurately representing the behaviors of unregistered Aggregate Distributed Energy Resources (DER) in sections 10(a) and 10(b) may be challenging. We

recommend including “estimated, assumed, or typical DER behaviors related to momentary cessation, tripping, ride-through, voltage control, frequency control, and voltage and frequency protection settings.”

Please see attached document for additional information

Likes 2	Scott Brame, N/A, Brame Scott; Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	
Document Name	

Comment

Portland General Electric (PGE) supports the Western Power Pool’s comments.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	
Document Name	

Comment

Both proposed standards (MOD-032-2; MOD-033-3) purport to define unregistered IBRs in a footnote (i.e., footnote 1 of each), with draft MOD-032-2 limiting its applicability with the phrase “as used in this standard.” Footnote treatment seems ill-suited to a definition that must be used consistently in a set of Milestone 3 and 4 standards to enable the data, modeling, planning and operational studies that are intended to be developed on a consistent basis to produce the reliability benefits Order 901 expressly contemplated. *See, e.g.,* Order 901, P 53. To better ensure consistent usage throughout the relevant standards, an appropriate unregistered IBR definition should be added to the Glossary. Indeed, inclusion of the unregistered IBR definition in a footnote is inconsistent with the proposal to include the DER definition in the Glossary.

In addition, the proposed footnote explanations of unregistered IBRs improperly use the term “Bulk-Power System connected” to delineate the IBRs to be covered. That term lacks the precision necessary for the registered entities (i.e., Transmission Owners and Distribution Providers) that are required to provide individualized data on such entities (proposed MOD-032-2, R2), and PCs, RCs, and TOPs that are required to validate system models using

this data “to facilitate achieving and maintaining adequate model accuracy” (proposed MOD-033-3, Purpose), or to provide confidence that the resulting reporting will consistently produce results that do not reflect gaps or double counting of IBRs. While the MOD-032-2 Technical Rationale, at 4, suggests that “bulk system-connected” can be shorthand for resources connected to the transmission system, it does not provide a controlling interpretation of the term “Bulk-Power System connected,” as used in the proposed standard, that can be consistently applied and relied upon.

Moreover, to the extent the MOD-032-2 Technical Rationale explanation is meant to inform the “unregistered IBRs” footnote, it fails to remedy the concern that there is no precise definition of Bulk-Power System that would enable a clean delineation of the IBR resources whose data is to be provided. The statutory term “bulk-power system,” like “local distribution,” is pertinent to the boundaries of FERC’s jurisdiction, and as stated in Order No. 773, “[t]he determination whether an element or facility is ‘used in local distribution,’ as the phrase is used in the FPA, requires a jurisdictional analysis that is more appropriately performed by the Commission.” *Revisions to Elec. Reliability Org. Definition of Bulk Elec. Sys. & Rules of Proc.,* Order No. 773, 141 FERC ¶ 61,236, P 69 (2012), *clarified on reh’g,* Order No. 773-A, 143 FERC ¶ 61,053, *compliance deadline extended,* 143 FERC ¶ 61,231, *clarified,* 144 FERC ¶ 61,174 (2013), *review denied sub nom. New York v. FERC*, 783 F.3d 946 (2d Cir. 2015).

In approving NERC’s criteria for fulfilling the directives to register IBRs that are “connected to the Bulk-Power System and that have an aggregate material impact on the reliable operation of the Bulk-Power System,” FERC found it reasonable for NERC to use “non-BES Inverter-Based Resource(s) 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.” *N. Am. Elec. Reliability Corp.*, 187 FERC ¶ 61,196, PP 10, 36-39 (2024). At the same time, FERC reiterated that determining the scope of the BPS is its call to make. *Id.* P 54 n.127. *See also id.* P 44.

Given FERC’s acceptance of the 60 kV cutoff as described above for Category 2 GO/GOP registration purposes as sufficient to meet its “connected to the BPS” directive, and Project 2024-01’s use of that same cut off for purposes of the GO/GOP Category 2 Glossary definitions (which recently received more than the requisite votes needed for approval), there is no reason for the proposed MOD-032-2 and MOD-033-3 footnotes to use vague BPS terminology. Instead, “unregistered IBR” should be added to the Glossary and defined using the already approved proxies for “BPS-connected,” *e.g.*: “non-BES Inverter-Based Resource(s) that do not 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.”

Context for and a summary of all concerns with the proposed MOD-032-2 definitions are provided in Question 1; additional concerns are provided in response to Questions 4 and 5.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
In MOD-032-2, Requirement 2.1 points to R1 part 1.1 which is attachment 1. Requirement 1 & 2 only mentions IBR but attachment 1 contains language about Wind plant type 1 & 2. From NERC definition Type 1 and 2 machines are not considered IBR. Therefore, this section needs to be carefully reworded to reduce ambiguity and confusion. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	
Document Name	
Comment	
NIPSCO supports MISO's comments below: "For short-circuit modeling under Item 3 of Attachment 1, Generator Owners (GOs) should be required to submit models that reflect their specific resource type, for example, synchronous generators versus inverter-based resources. Relying solely on positive, negative, and zero sequence data may be insufficient for accurately representing inverter-based resources, which often require more detailed modeling parameters." "Regarding steady-state generation (Item 3), there is no need to distinguish between generating units and storage resources, as batteries and pumped storage units are already categorized as generators. If the drafting team wishes to explicitly include storage resources, this clarification would be better suited as a footnote rather than a separate classification."	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	

Comment
In MOD-032-2, Requirement 2.1 points to R1 part 1.1 which is attachment 1. Requirement 1 & 2 only mentions IBR but attachment 1 contains language about Wind plant type 1 & 2. From NERC definition Type 1 and 2 machines are not considered IBR. Therefore, this section needs to be carefully reworded to reduce ambiguity and confusion. Alison Mackellar on behalf of Constellation Segments 5 and 6

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; Kris Kirkegaard, 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
SMUD and BANC feel that the implementation plan for MOD-032-2 is too restrictive when it comes to implementing new dynamic data for the many new generation assets being added to the scope of MOD-032-2 (e.g. aggregate DER and unregistered IBR). We support the comments submitted by Tacoma Power that justify more time being added for entities to meet compliance and suggest that a 24-to-36-month implementation plan is appropriate. Lastly, we encourage the standards drafting team (SDT) to refrain from creating a definition in a footnote. The changes proposed in MOD-032-2 and the initial ballot of MOD-033-3 both define the term “unregistered IBR” in a footnote. This important term could very well be used in additional Standards when the Milestone 4 directives are addressed and, therefore, should be defined in a formal definition included in the Glossary of Terms Used in the NERC Reliability Standards (NERC Glossary). A Standards Authorization Request was drafted to create a formal definition for “unregistered IBR”. The SDT should work with NERC and the SDT for MOD-033-3 to ensure the same definition is being used for this term and that it is formally included in the NERC Glossary.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)).

In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement?

TOP-003 and IRO-010 standards pertain to the data specification and exchange requirements for Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Time Horizons for requirements within MOD-032-2 [Long-Term Planning] and TOP-003-8/IRO-010-7 [Operations Planning] should align with each other. Models created in MOD-032-2 will be utilized for Operations Planning and Real-time Assessments. As such, data exchange requirements in the form of “model submissions” should reflect all valid time frames, including entities that need to receive this data as part of their required assessments.

Attachment 1, Column #2 (item 7(a)) IBR behaviors related to momentary cessation, tripping, Ride-through, and frequency control

Likes 0	
Dislikes 0	

Response

Pirouz Honarmand - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

When the DER data is not available the SDT suggests estimating it. Is it possible to include technical rationale and guidance to help entities to proceed with this estimate? The guide should help entities to apply and use consistent estimating approaches.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	

We support the NPCC RSC comments

Comments pertaining to IRO-010:
R3 Lower VSL: Missing “R1”. Should read “…to meet one of the parts of R1, Part 1.5” as used in the Moderate and High VSL. Furthermore, there is a space missing between R1 and Part 1.5 in the Moderate VSL.

M3: Reliability Coordinator is listed twice in the measure.

C1.2: Suggest adding “and information” to the 2nd bullet to better reflect R2 and M2. As posted, it currently reads “The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2”. Suggest changing to “The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2”.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE noticed the implementation plan could provide more clarity on the retirement dates, initial performance dates, and phased-in compliance dates. First, Texas RE noticed the retirement date for MOD-032-2 is “immediately prior” to the effective date of the standard. The initial performance and compliance dates, however, are 12 months after the effective date of the standard. Texas RE is concerned this could be interpreted to leave a gap in compliance for 12 months. The drafting team may be attempting to address this in the last paragraph of page 3, “Entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032- 2”, although it is not clear that verbiage is referring to that potential gap between the effective date of the standard and the phased-in compliance dates.

Texas RE also inquires as to the difference in initial performance dates and compliance dates. This implementation plan seems to describe them in the same way. It is Texas RE's understanding, however, that the initial performance date is for periodic requirements, so registered entities (and auditors) know when the first time the action is to take place, and thus start the periodic tracking of the activity. Compliance dates, on the other hand, refer to phased-in dates after the effective date of the standard so registered entities have time to complete certain activities. Is the intent of the initial performance date to refer to the periodicity in Requirement Part 1.3? There do not appear to be periodic activities in Requirements R2, R3, and R4, and thus a compliance date (phased-in dates) would be appropriate for those requirements.

Additionally, Texas RE noticed that the VRFs are included in the VSL table for IRO-010-6, but are not in the VSL tables for MOD-032-2 and TOP-003-8. The VRFs do appear to be in the requirements for all proposed standards.

Lastly, Texas RE requests the SDT consider adding the "ERO Approved Criteria for Acceptable Models" to the Associated Documents section of each standard (Section E for MOD-032-2, Section F for IRO-010-6 and TOP-003-8).

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez

Answer	
Document Name	

Comment

Please clarify if residential roof top solar will be subject to order and study criteria.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC

Answer	
Document Name	

Comment

Comments pertaining to IRO-010:

R3 Lower VSL: Missing “R1”. Should read “…to meet one of the parts of R1, Part 1.5” as used in the Moderate and High VSL. Furthermore, there is a space missing between R1 and Part 1.5 in the Moderate VSL.

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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

1. Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)).

2. In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement?

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4. Add the following in **bold**, and remove the following in *italics:*

Attachment 1, Column #2 (item 7(a)) IBR **behaviors** *capabilities* related to momentary cessation, tripping, Ride-through, and frequency control.

5. Attachment 1, Column #2 (items 7(a) and 10(a)). Although there are provisions for representing voltage and frequency protection settings in positive sequence simulations, the terms “momentary cessation, tripping, and ride-through” are too ambiguous. These concepts may not be fully representable in positive sequence phasor domain simulations and lack the necessary clarity to ensure compliance.

6. Attachment 1, Column #2, Item 10: ITC recommends establishing a MW threshold level for requiring unregistered IBRs, as determined by the Planning Coordinator (PC) and Transmission Planner (TP) in R1. Additionally, due to the lack of standardized distribution DER performance requirements, accurately representing the behaviors of unregistered Aggregate Distributed Energy Resources (DER) in sections 10(a) and 10(b) may be challenging. We recommend including “estimated, assumed, or typical DER behaviors related to momentary cessation, tripping, ride-through, voltage control, frequency control, and voltage and frequency protection settings.”

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response

Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	

ERCOT, Midcontinent ISO, Southwest Power Pool, and California ISO abstain from the response to this question.

For short-circuit in Attachment 1 under item 3, the GO should be required to submit a model based on their resource type i.e. synchronous generator versus inverter based. Positive, negative and zero sequence data may not cover all required modeling data for inverter-based resources.

For Steady State generation (item #3), there is no need to separate between generating units and storage units as battery and pumped storage resources are considered generators. If the drafting team wants to clarify that storage units are included, then that should be a footnote.

Likes 0	
Dislikes 0	

Response

Colten Mitchell - Indiana Municipal Power Agency - 4	
Answer	
Document Name	
Comment	

Both proposed standards (MOD-032-2; MOD-033-3) purport to define unregistered IBRs in a footnote (i.e., footnote 1 of each), with draft MOD-032-2 limiting its applicability with the phrase “as used in this standard.” Footnote treatment seems ill-suited to a definition that must be used consistently in a set of Milestone 3 and 4 standards to enable the data, modeling, planning and operational studies that are intended to be developed on a consistent

basis to produce the reliability benefits Order 901 expressly contemplated. *See, e.g.,* Order 901, P 53. To better ensure consistent usage throughout the relevant standards, an appropriate unregistered IBR definition should be added to the Glossary. Indeed, inclusion of the unregistered IBR definition in a footnote is inconsistent with the proposal to include the DER definition in the Glossary.

In addition, the proposed footnote explanations of unregistered IBRs improperly use the term "Bulk-Power System connected" to delineate the IBRs to be covered. That term lacks the precision necessary for the registered entities (i.e., Transmission Owners and Distribution Providers) that are required to provide individualized data on such entities (proposed MOD-032-2, R2), and PCs, RCs, and TOPs that are required to validate system models using this data "to facilitate achieving and maintaining adequate model accuracy" (proposed MOD-033-3, Purpose), or to provide confidence that the resulting reporting will consistently produce results that do not reflect gaps or double counting of IBRs. While the MOD-032-2 Technical Rationale, at 4, suggests that "bulk system-connected" can be shorthand for resources connected to the transmission system, it does not provide a controlling interpretation of the term "Bulk-Power System connected," as used in the proposed standard, that can be consistently applied and relied upon.

Moreover, to the extent the MOD-032-2 Technical Rationale explanation is meant to inform the "unregistered IBRs" footnote, it fails to remedy the concern that there is no precise definition of Bulk-Power System that would enable a clean delineation of the IBR resources whose data is to be provided. The statutory term "bulk-power system," like "local distribution," is pertinent to the boundaries of FERC's jurisdiction, and as stated in Order No. 773, "[t]he determination whether an element or facility is 'used in local distribution,' as the phrase is used in the FPA, requires a jurisdictional analysis that is more appropriately performed by the Commission." *Revisions to Elec. Reliability Org. Definition of Bulk Elec. Sys. & Rules of Proc.,* Order No. 773, 141 FERC ¶ 61,236, P 69 (2012), *clarified on reh'g,* Order No. 773-A, 143 FERC ¶ 61,053, *compliance deadline extended,* 143 FERC ¶ 61,231, *clarified,* 144 FERC ¶ 61,174 (2013), *review denied sub nom. New York v. FERC*, 783 F.3d 946 (2d Cir. 2015).

In approving NERC's criteria for fulfilling the directives to register IBRs that are "connected to the Bulk-Power System and that have an aggregate material impact on the reliable operation of the Bulk-Power System," FERC found it reasonable for NERC to use "non-BES Inverter-Based Resource(s) 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." *N. Am. Elec. Reliability Corp.*, 187 FERC ¶ 61,196, PP 10, 36-39 (2024). At the same time, FERC reiterated that determining the scope of the BPS is its call to make. *Id.* P 54 n.127. *See also id.* P 44.

Given FERC's acceptance of the 60 kV cutoff as described above for Category 2 GO/GOP registration purposes as sufficient to meet its "connected to the BPS" directive, and Project 2024-01's use of that same cut off for purposes of the GO/GOP Category 2 Glossary definitions (which recently received more than the requisite votes needed for approval), there is no reason for the proposed MOD-032-2 and MOD-033-3 footnotes to use vague BPS terminology. Instead, "unregistered IBR" should be added to the Glossary and defined using the already approved proxies for "BPS-connected," *e.g.*: "non-BES Inverter-Based Resource(s) that do not 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."

Context for and a summary of all concerns with the proposed MOD-032-2 definitions are provided in Question 1; additional concerns are provided in response to Questions 4 and 5.

Likes 1	American Municipal Power, 5, Ritts Amy
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

Several ACES Members have expressed their concerns regarding their ability to collect and submit all of the information identified in the proposed draft of MOD-032-2, particularly the proposed dynamic data. Therefore, ACES suggests that the drafting team should consider a minimum threshold value for dynamic DER data. In our opinion, such a threshold would be consistent with NERC's precedent for developing risk-based Reliability Standards and would prevent an insurmountably large compliance being placed upon the applicable registered entities.

PPI generally agrees with these comments, with one exception. In regard to question 2, we believe the TP, not the TO, should be the entity responsible for estimating DER data, as the TP is currently responsible for submitting load forecasts and similar data. DER's are essentially negative load.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	Project 2022-02 _ EEI Near Final Draft Comments _ MOD-032 IRO-10 TOP-002 Draft 1_ Rev. 0h _ 5_14_2025 (1).docx

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

For this question, ERCOT does not join the comments submitted by the IRC SRC.

Likes 0	
Dislikes 0	

Response

Scott Thompson - TXNM Energy - 3

Answer	
Document Name	
Comment	
This project incoporates many definitions or soon to be definitions that have been or will be changed. It would be nice if all of the SDT's from all of the FERC order 901 projects would get together and form a concise voice and vision on how to incorporate those new definitions into these new and modified standards.	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	
It will likely require industry more than three years to comply with MOD-032-2, so the three year timeline proposed in the Implementation Plan should be extended. The Consideration of FERC Order 901 Directives document notes: "It is understood that based on what is being required via MOD-032, industry would need at least one year to gather data, hold meetings with respective OEM or developers to gather models needed, and then an additional two years to update models based on the ERO Approved Criteria for Acceptable Models document, etc." As was established at length in the September 2024 PRC-029 technical workshop and recent industry comments on FERC's Notice of Proposed Rulemaking to approve PRC-029, coordination with OEMs is challenging and time consuming, particularly for vintage generator technology that is no longer supported. The Consideration of FERC Order 901 Directives document notes the uncertainty in the timeline for that process, noting that initial OEM coordination may take "at least one year." Extending the effective date should still allow NERC to meet the 2030 deadline FERC suggested in Order 901. This will ensure model development is not rushed, which could potentially endanger reliability if models are not adequately vetted.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	
Document Name	
Comment	
No comments	
Likes 0	

Dislikes 0	

Response

Usama Tahir - Seminole Electric Cooperative, Inc. - 3

Answer	
Document Name	

Comment

Seminole Electric Cooperative's commment is that the DER definition does not guarantee that the resource(s) included influence the BPS that is in federal jurisdiction. The current definition may place unnecessary compliance burden on local distribution that is under state authority.

Likes 0	
Dislikes 0	

Response

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

I. Introduction

1. The Electric Power Research Institute (EPRI)[1] respectfully submits these comments (This Response) in response to North American Electric Reliability Corporation (NERC)'s request for formal comment on Project 2022-02 Uniform Modeling Framework for IBR, issued April 17, 2025.

2. EPRI closely collaborates with its members inclusive of electric power utilities, Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs), as well as numerous other stakeholders, domestically and internationally. In its role, EPRI conducts independent research and development relating to the generation, delivery, and use of electricity for public benefit by working to help make electricity more reliable, affordable and environmentally safe. EPRI's comments on this topic are technical in nature based upon EPRI's research, development, and demonstration experience over the last 50 years in planning, analyzing, and developing technologies for electric power.

3. EPRI research and technology transfer deliverables are generally accessible on its website to the public, either for free or for purchase, and occasionally subject to licensing, export control, and other requirements.[2] The publicly available and free-of-charge milestone reports from a U.S. Department of Energy (DOE)- and EPRI member-funded research project, Adaptive Protection and Validated Models to Enable Deployment of High Penetrations of Solar PV ("PV-MOD"), [3] and other research deliverables substantiate many of the comments made in This Response.

4. While not a standards development organization (SDO), EPRI conducts research and demonstration projects in relevant areas as well as facilitates knowledge transfer and collaboration that SDOs may, at times, use to inform technical and regulatory standards development, such as in Institute of Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), International Council on Large Electric Systems (CIGRE), and NERC.[4]

II. Conclusion

5. EPRI appreciates the opportunity to provide NERC with its technical recommendations and comments on these important topics related to Reliability Standards for IBRs. EPRI looks forward to working with its members, NERC, and other stakeholders on providing further independent technical information on these important questions.

III. Contact Information

Jens C. Boemer, Technical Executive

Email: JBoemer@epri.com

[1] EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1996, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

[2] https://www.epri.com (last accessed, May 16, 2025)

[3] PV-MOD Project Website. EPRI. Palo Alto, CA: 2024. [Online] https://www.epri.com/pvmod (last accessed, May 16, 2025)

[4] For transparency, we would like to disclose that EPRI collaborates with other organizations such as IEEE, IEC, CIGRE, and NERC; however, EPRI is not a regulatory- or standard-setting organization. EPRI research is often considered in the development of recommendations, guidelines, and best practices that are not determinative.

Likes 0	
Dislikes 0	

Response

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2022-02 Uniform Modeling Framework for IBR | Draft 1
Comment Period Start Date:	4/17/2025
Comment Period End Date:	5/16/2025
Associated Ballot(s):	2022-02 Uniform Modeling Framework for IBR | Draft 1 Implementation Plan IN 1 OT 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 | Non-binding Poll IN 1 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 IN 1 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 | Non-binding Poll IN 1 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 IN 1 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 | Non-binding Poll IN 1 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 IN 1 ST

There were 82 sets of responses, including comments from approximately 174 different people from approximately 105 companies representing 8 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 proposed MOD-032-2 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

2. Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system? If not, what entity would be in a better position to provide that data and add justification?

3. Do you agree with the proposed IRO-010-5 and TOP-003-8 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

4. Do you agree with the proposed DER definition? Please refer to the technical rationale, which provides rationale behind the drafting team's intent and previous definitions proposed. If you do not support the definition as proposed, please explain the changes that, if made, would result in your support.

5. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-5, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

6. Do you agree with the proposed ERO Approved Criteria for Acceptable Models document? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

7. Provide any additional comments for the 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		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
Santee Cooper	Chris Wagner	1		Santee Cooper	Weijian Cong	Santee Cooper	1,3,5,6	SERC

					Chris Wagner	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group, Inc.	3	RF
					Michelle Hribar	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
					Candace Morakinyo	WEC Energy Group, Inc.	4	RF
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC

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,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	James Shultz	Hoosier Energy Electric Cooperative	1	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
Black Hills Corporation	Josh Schumacher	6		Black Hills Corporation Segments 1, 3, 5, 6	Trevor Rombough	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC

					Josh Schumacher	Black Hills Corporation	6	WECC
Midcontinent ISO, Inc.	Kirsten Rowley	2		ISO/RTO Council (IRC) Standards Review Committee (SRC)	Elizabeth Davis	PJM	2	RF
					Kirsten Rowley	Midcontinent ISO, Inc.	2	RF
					John Pearson	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Joshua Phillips	Southwest Power Pool, Inc. (RTO)	2	MRO
					Kennedy Meier	ERCOT	2	Texas RE
					Jamie Johnson	California ISO	2	WECC
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
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

Northeast Power Coordinating Council	Ruida Shu	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

Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	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

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
Emma Halilovic	Hydro One	1,3	NPCC
Philip Nichols	National Grid	1	NPCC
Emma Halilovic	Hydro One	1,3	NPCC
Caver Powers	Utility Services	5	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
Dominion - Dominion Virginia Power	Victoria Crider	3		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable

					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable

1. Do you agree with the proposed MOD-032-2 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA does not support the proposed revisions in MOD-032-2, specifically, R2.1. BPA believes the TO is not the appropriate registered entity to be responsible for providing estimations of unregistered load. BPA has 133 load modeling entities within its footprint, with a combined winter peak load of 12.2 GW. 110 of these entities are unregistered, which accounts for 6.4 GW of the total load. BPA, as a TO, does not have visibility into an unregistered entity's systems to provide an estimate of the data at any level of accuracy. BPA believes an uninformed estimate could negatively impact system reliability. BPA advocates that the best way to close the data gap is to close the registration gap. BPA recommends unregistered DPs become registered if only to supply IBR and DER data. BPA suggests a new compliance registry "DP-DER" registration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 901 P104 states "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." Please see the updated TR, which provides some examples of methods on how to complete estimations	

with little data or no data. While the team understands the importance of accuracy, it is important to have an allowance for estimation when data is not available. The DT updated MOD-032 to better align in having the TP and PC identify the appropriate entity responsible for providing data associated with unregistered IBR and DER. As discussed in the TR, modifying NERC registration criteria is not a feasible option for addressing FERC 901 directives within the required timelines.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy asks for clarification on the following:
Footnote 1 states:
As used in this standard, the phrase “unregistered IBR” refers to a Bulk-Power System connected IBR that does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

Footnote 1 introduces the term “unregistered IBR” but does not adequately define it. Does the term “Unregistered IBR” only refer to IBRs that meet Category 2 criteria? This is not clear in the footnote as written.

Also, Project 2024-01 passed on May 7, 2025, which adds “Category 2” IBRs to the Generator Owner definition. Does that change the meaning of Footnote 1 since Generator Owner now includes both Categories 1 and 2? Would this change the meaning of the footnote 1 to include unregistered IBRs not already applicable under Categories 1 and 2?

In addition, FirstEnergy supports EEI’s comments which state:

EEI does not agree that enforceable Reliability Standards should be reliant on external documents such as the document titled “ERO Approved Criteria for Acceptable Models” (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. Moreover, the Commission did not direct NERC to develop such a document but instead directed NERC “to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria” (emphasis added; FERC Order 901, P161).). To better align with FERC Order 901, we offer the following comments and suggested edits in boldface below:

Requirement R1

EEI does not support maintaining model criteria within ERO document titled ERO Approved Criteria for Acceptable Models for the reasons detailed in our response to Question 6 below. To address this concern, we offer the following modifications to requirement R1 below, which we believe would satisfy FERC Order 901 directives, place the criteria back within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection. These edits are limited to part 1.2 in boldface below:

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1 The data listed in Attachment 1, including the responsible entity for each required item.

1.2 Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization (ERO) Specifications for the following items for dynamic models submitted in accordance with Attachment 1:

1.2.1 A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.2.2 Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s), or a technical justification for the submission and use of user-written models if such models are permitted.

1.2.3 Criteria for any submitted user-written models including, at a minimum, documentation, and performance criteria to minimize the risk of non-convergence and other issues. The PC's user-written model criteria must be made available to all other TP/PC's within the Interconnection for review and comment, and approval where the usage of the user-written model represents a shared impact.

1.3 Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.3.1 **D**ata format;

1.3.2 Level of detail to which equipment shall be modeled;

1.3.3 Case types or scenarios to be modeled; and

1.3.4 A schedule for submission of data at least once every 13 calendar months.

1.4 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

Footnote 1: For example, the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases.

Requirement R2

EEI does not support Requirement R2, part 2.1 because this requirement places compliance obligations on the TO that they have no practical method of fulfilling without the support of the unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While it is unclear how DER data from unregistered entities might impact BPS reliability, TO will be limited in their ability to fulfill their compliance obligations without the direct assistance and participation for unregistered DPs. To address this concern, guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DPs. We additionally offer some suggested boldface edits to Requirement R2 to add additional clarity:

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

2.1 For unregistered Inverter-based Resource (IBR) data, the responsible TO, whose transmission system these resources are connected, shall develop estimates of the aggregated unregistered IBRs including estimated modeling data. The TO shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations.

2.2 For Distributed Energy Resource (DER) data the responsible DP shall develop estimates of the aggregated DER connected to their distribution systems including aggregated modeling data. The DP shall also include an explanation of the limitations of the aggregated data as provided and the methods used for their estimations.

2.3 For distribution systems that are interconnected to a responsible TO system, where no registered DP exists, the TO shall document all attempts to gather aggregate estimates of DER capacity from the unregistered DP.

2.3.1 If the TO is success in gathering aggregate estimates of DER capacity from the unregistered DP, the data shall be forwarded to the responsible PC and TP so they can assess if the DER capacity on the unregistered DP's distribution system represents a material impact on the BPS.

2.3.1.1 If the PC & TP determines a material impact exists, their findings shall be reported to the ERO for further actions.

2.3.1.2 If the PC & TP determine there is not a material impact, no further actions are required by the responsible TO, unless further actions are requested by the PC & TP.

2.3.2 If the TO is unsuccessful in gathering aggregate estimates of DER capacity from the unregistered DP, they are to report their inability to collect the required data to both the responsible PC and TP, who will report the issue to NERC for further actions.

Attachment 1 Concerns: EEI offers the following comments and suggested edits (in boldface) to Attachment 1 below:

Item 2 – It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for in various modeling scenarios.

Item 9 – TOs are entirely dependent on responsible **registered** DPs and should therefore be removed from having direct responsibility for Aggregate DER data. Additionally, 9c should be edited (see boldface edit below) to better align with what DP are capable of collecting (i.e., aggregate DER data by storage types).

Dynamics Concerns

Item 5 - It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for various modeling scenarios.

Item 7 – Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR. To address our concerns, we offer the following boldface edits to Item 7:

7. Inverter-Based Resource **[GO, TO]**

a. Registered IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control **[GO]**

b. **Aggregated capability of non-registered IBRs connect to the BPS including estimates related to momentary cessation, tripping, Ride-through, and frequency control [TOs]**

Item 10 – TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed. To address our concerns, we offer the following boldface edits:

10. Aggregate Distributed Energy Resource (DER) data

a. **Estimates of aggregated** DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. **[DP, UFLS only DPs]**

b. **I**ndication whether DER**s is subject to tripping in conjunction with are part of any** UFLS or UVLS **schemes and provide estimates of the affected aggregated capacity on those schemes**. **[DP, UFLS only DPs]**

Footnote concerns

Footnote 1: EEI does not agree with Footnote 1. Data requirement obligations should be clearly specified within each sub-bullet of each column for both steady-state and dynamics to ensure responsible entities understand their roles.

Footnote 2: EEI suggests the following clarifying edits to footnote 2 in boldface:

For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. **A The** Distribution Provider is the **typical** responsible entity for providing this information, **generally** through coordination with the Transmission Owner.

Footnote 4: EEI does not agree that IBRs should be generically identified as storage devices. Instead, Battery Energy Storage System (BESS) should replace IBR in footnote 4. Note the following boldface edits:

This includes **IBR battery energy storage systems**, synchronous condensers, and pumped storage.

Footnote 5: Ambiguous terms like typical should not be included in NERC Reliability Standard. We additionally feel that it should be made clear the limits of TO responsibilities regarding unregistered IBRs.

The transmission owner is the **typical** responsible entity for collecting and providing **aggregate** data for unregistered IBRs that are not DERs **and directly connected to their portion of the BPS.**

Footnote 6: TO and DP have no ability to collect or provide aggregate data for DERs that are not connected directly to their system. If DER data is needed from unregistered DP to preserve the reliability of the BPS, then those entities should be registered. The following boldface edits have been provided to clarify what registered DP are capable of providing under MOD-032:

The Distribution Provider is the responsible entity for collecting and providing **aggregate** data for DER connected to **their distribution** system.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model into Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to “develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions” (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be

considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC Staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.

In addition, multiple commenters submitted comments about the phrase "unregistered IBR" as it is used in proposed MOD-032 as well as other proposed Reliability Standards addressing the FERC Order No. 901 Milestone 3 directives. The drafting team has revised footnote 1 to more clearly refer to the resources that are intended to be captured in this phrase and provides the following additional explanation in response to the comments.

In summary, the phrase "unregistered IBR" has been revised to refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application.

The drafting team has been advised that, as footnote 1 is explaining a phrase used in the requirement text, the footnote is properly used in the standard and is considered a mandatory and enforceable part of the standard.

The drafting team chose to use the phrase "unregistered IBR" in proposed MOD-032 to establish consistency with FERC Order No. 901, which used the shorthand phrases "registered IBR", "unregistered IBR", and "IBR-DER" to define the scope of its directives. Relevant to this discussion, Order No. 901 used the phrase "registered IBR" to refer to IBRs registered with NERC (or which would be registered pursuant to the Commission's directives in Registration of Inverter-based Resources, 181 FERC ¶ 61,124 (2022) and therefore, subject to the Reliability Standards, and the phrase "unregistered IBR" to refer to 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).

It is important to note that Order No. 901 predated the changes NERC made to the Rules of Procedure to ensure that the owners and operators of such IBR resources would be registered with NERC for mandatory compliance purposes. NERC does not register IBRs as resources, but rather the owners of such resources based on the registry criteria for Generator Owner and Generator Operator. There are two categories of each: owners and operators of BES Facilities (category 1 GOs/GOPs); and owners and operators of 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 (category 2 GOs/GOPs).

In Order No. 901 parlance, ownership or operation of IBR resources meeting these criteria would require owner/operator registration, and therefore would be considered "registered IBRs".

In Order No. 901 parlance, ownership or operation of IBR resources that do not meet these criteria, but are connected to a transmission system (i.e., are not Distributed Energy Resources), would not require owner/operator registration, and therefore would be considered "unregistered IBR."

The drafting team appreciates the suggested alternatives to the use of the Order No. 901 phrase "unregistered IBR" to describe the resources that are intended to be covered. It has considered establishing a defined Glossary term (Unregistered IBR), as well as explicitly defining in the above-the-text requirement language what is an unregistered IBR based on the NERC compliance registry criteria.

The drafting team believes that, with the revised clarification, there is no need to create an additional defined term for "unregistered IBR." Such a term is not likely to aid in understanding, as the definition would be defining the term in the negative relative to other defined terms (i.e., an IBR for which the owner/operator would not be required to register with NERC as a Generator Owner/Generator Operator).
The drafting team also determined that replacing the phrase "unregistered IBR" in the requirement text with a more detailed description of what is an "unregistered IBR" that draws from the GO/GOP registry criteria (e.g., "not an IBR BES Facility, not a non-BES inverter based generating resource that either has or contributes 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, and not a DER") would lead to lengthier requirements that are less readable without providing additional clarity.

The drafting team believes that the revised footnote is clearer as to the scope of the IBR intended to be covered while maintaining readability.

Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES adopts EEI's comments for MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Attachment One's 7a and 10a are both concerning. While there are provisions for representing voltage and frequency protection settings in positive sequence simulations, "momentary cessation, tripping, and ride-through" are too open-ended, may not be able to be represented completely in positive sequence phasor domain simulations, and lack the clarity needed to be certain of compliance. AEP suggests the following be used instead: 7a. "In the absence of project specific data, include estimated, assumed, or typical voltage and frequency protection settings." 10a. "Include estimated, assumed, or typical aggregate voltage and frequency protection settings." AEP recommends that a MW threshold level be established for requiring unregistered IBRs. AEP suggests 10 MW and above or as otherwise determined by the PC and TP in R1. In addition, there should also be a threshold level for requiring aggregate DER (affecting steady-state	

items 2 and 9, dynamics items 5 and 10) so as not to be found non-compliant for trivial amounts. AEP suggests 5 percent or greater of a TO's or DP's peak load or as determined by the PC and TP in R1.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for your comment. Attachment 1 does not create obligations for entities to provide data, but specifies the data items that need to be covered by the PC/TP data reporting procedures and requirements. For DER, the aggregated nature means some level of estimate or assumption is inherent (just like load data). Requirement R2, Part 2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather unregistered IBR or DER data. The TR information about Inferring DER Capabilities and the new section on estimation speaks more clearly to that concept. The proposed footnote 7 is intended to allow the PC/TP to define DER thresholds for a local area if appropriate.	
Julie Hall - Entergy - 6	
Answer	No
Document Name	
Comment	
Entergy has concerns about relying on "estimation of modeling data and parameters" required by R2.1 and introducing unverified DER model information into planning models and demonstrating compliance based on those estimations. **Footnote 3 in Attachment 1 – requires DPs make assumptions about generation output of behind the meter DER facilities to provide a gross demand number. Entergy proposes that R2.1 DER data be modeled as an aggregate MW generation as a percentage of the feeder, substation transformer, or substation load. To optimize attaining meaningful results considering the proposed intense data demands set forth, Entergy recommends inclusion of a penetration threshold (ex: 20% of a substation gross load) for which these new modeling requirements become applicable.**	
Likes 0	

Dislikes 0	

Response

Thank you for your comment. Given the FERC Order requirement to account for aggregate IBR-DER, the aggregate demand must be the gross value to avoid double counting the DER impact. Estimation options could include an aggregate capacity if no better information is available. Thresholds may be addressed by footnote 7.

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

TVA does not support the proposed revisions in MOD-032-2.

Regarding R1.2, the ERO Criteria for Acceptable Models does not have industry consensus and was not established through the standards process. TVA does not believe it should be referenced in a compliance standard. In its place, TVA recommends specifications for standard models (where appropriate and available), user-written models (where appropriate and with adequate documentation), and other models (when no alternative is available and requiring justification for use).
R2.1 asks entities that can't gather IBR/DER data to estimate the data. The model data that will be gathered with this provision is likely of low value and will potentially lead to more inaccurate models or models that have different issues. TVA does not believe the modeling responsibility for unregistered IBRs and aggregate DERs belongs with the TO and DP when that data, or lack there-of, must be estimated. Estimations of data without adequate information could negatively affect modeling. It is not uncommon for the TO and DP to lack visibility of unregistered IBRs and aggregate DERs. TVA recommends expanding the requirement to include “or justification on why unregistered IBR and/or aggregate DER was not modeled or estimated” to account for these circumstances.

Regarding Attachment 1 Dynamics 10.b, this data could be difficult to accurately model for situations where the DP will often reconfigure their systems and move DERs between feeders. TVA recommends removing 10.b.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO, does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 in the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.

In addition, Representing the impact of UVLS and UFLS on DER (i.e., tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.	
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 review, and offers the following comments and suggestions. Requirement R1 references the ERO-maintained Approved Criteria for Acceptable Models document. This document is not part of the Standard and may pose compliance challenges if updated outside of the Standard Development Process. The process to maintain the list of models (e.g. Unacceptable Model List) relies on NERC's determination on what would constitute an acceptable change implementation timeline, i.e. effective date. For example, if the ERO added an existing data model to the List of Unacceptable Models in the ERO-maintained document without accounting for an adequate implementation timeline, entities may be in noncompliance on the effective date of the revised ERO document even though Standard had not been revised. BC Hydro recommends that this document be included in the Standard, or otherwise provide for a change management process aligned with the Standard Development Procedures.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO, does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among

generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 in the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	No
Document Name	
Comment	

While the modifications are an improvement there are still areas that need to be addressed. For example, assigning the DP the burden to provide data on behalf of not registered DER's will add compliance obligations and will not provide the accurate data needed for an improved system model. A better approach is to provide a mechanism for the unregistered DER"s to become registered and therefore subjected to the same compliance obligations as registered DER's.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 901 P 102 "directs NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1) transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System." In addition, FERC Order P157and P161 identify a responsible entity for DER data in cases where there is no registered DP. P157 states: "We believe the development of new or modified Reliability Standards is an important corollary to NERC's ongoing effort to identify and register generator owners and operators of IBRs. Although NERC's registration changes will not at this time address IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, we believe APS's concerns regarding system-wide model validation is addressed in NERC's Reliability Guidelines[1] and through the use of the EPRI DER Settings Database. We recognize that some distribution providers may not be able to provide a precise set of modeling data and parameters that accurately represent IBR-DERs in the aggregate. For these situations, NERC has provided a technical means to estimate in aggregate the needed IBR-DER modeling data and parameters (i.e., for the DER_A model) in the IBR-DER Data Collection Guideline.[2] Further, NERC's 2021 Aggregate DER Model Verification Guideline provides transmission planners and planning coordinators with tools and techniques that can be adapted for their specific systems to verify that aggregate DER models (i.e. DER_A models) are a suitable representation of these resources in planning	

[1] *See generally* IBR-DER Data Collection Guideline; Aggregate DER Model Verification Guideline.

[2] *See generally* IBR-DER Data Collection Guideline.

assessments.[3] Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models." And P161 states: "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal to provide additional specificity to explain coordination and keep up to date in a timely manner the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate in the system models.[4] Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model. Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these resources in the system models. For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives. NERC may implement this directive by modifying Reliability Standards MOD-032-1 and MOD-033-2 or by developing new Reliability Standards to establish requirements mandating an annual[5] process to coordinate, validate, and keep up-to-date the transmission planning, operations, and interconnection-wide models." As discussed in the TR, modifying NERC registration criteria is not a feasible option for addressing FERC 901 directives within the required timelines. Attachment 1 does not create obligations for entities to provide data but specifies that data items that need to be covered by the PC/TP data reporting procedures and requirements. Thus, DT proposal allows the PC/TP flexibility to identify the best responsible entity for their area (though

[3] *See generally* Aggregate DER Model Verification Guideline.

[4] NOPR, 181 FERC ¶ 61,125 at P 85.

[5] *See* Reliability Standard MOD-032-1 at 15 (explaining that "presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year").

admittedly, it would likely be the DP in scenario described). R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather DER data.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Under R1 the ERO-maintained Criteria for Acceptable Models is referenced. This document was not developed under the standard process and therefore does not have industry consensus. Tri-State is concerned that changes to this document outside of the standard could pose a potential problem.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves. Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use. In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to “develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions” (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching	

goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO, does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from

the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's comments regarding the modifications to MOD-032-2. The first issue of concern being the use of the external document "ERO Approved Criteria for Acceptable Models" to establish enforceable compliance requirements. We agree with EEI's suggestion that this be put back into the standard itself as part of Attachment 1. Black Hills Corporation also agrees with the EEI's conclusion that Section R2 places inappropriate burdens on the TO to gather information on installations they may have had no part in interconnecting and have no ability to compel those entities to provide information. We agree with their modifications to this section as well as attachment 1 that clarify which entities should typically be responsible for collecting data on these devices.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among

generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns. The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions. The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation does not agree with the addition of requirement 2.1. Unregistered entities do not fall under the purview of this standard or NERC requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Multiple commenters submitted comments about the phrase "unregistered IBR" as it used in proposed MOD-032 as well as other proposed Reliability Standards addressing the FERC Order No. 901 Milestone 3 directives. The drafting team has revised footnote 1 to more clearly refer to the resources that are intended to be captured in this phrase and provides the following additional explanation in response to the comments. In summary, the phrase "unregistered IBR" has been revised to refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application.	

The drafting team has been advised that, as footnote 1 is explaining a phrase used in the requirement text, the footnote is properly used in the standard and is considered a mandatory and enforceable part of the standard.

The drafting team chose to use the phrase "unregistered IBR" in proposed MOD-032 to establish consistency with FERC Order No. 901, which used the shorthand phrases "registered IBR", "unregistered IBR", and "IBR-DER" to define the scope of its directives.
Relevant to this discussion, Order No. 901 used the phrase "registered IBR" to refer to IBRs registered with NERC (or which would be registered pursuant to the Commission's directives in Registration of Inverter-based Resources, 181 FERC ¶ 61,124 (2022) and therefore subject to the Reliability Standards, and the phrase "unregistered IBR" to refer to 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).

It is important to note that Order No. 901 predated the changes NERC made to the Rules of Procedure to ensure that the owners and operators of such IBR resources would be registered with NERC for mandatory compliance purposes. NERC does not register IBRs as resources, but rather the owners of such resources based on the registry criteria for Generator Owner and Generator Operator. There are two categories of each: owners and operators of BES Facilities (category 1 GOs/GOPs); and owners and operators of 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 (category 2 GOs/GOPs).

In Order No. 901 parlance, ownership or operation of IBR resources meeting these criteria would require owner/operator registration, and therefore would be considered "registered IBRs".

In Order No. 901 parlance, ownership or operation of IBR resources that do not meet these criteria but are connected to a transmission system (i.e., are not Distributed Energy Resources) would not require owner/operator registration, and therefore would be considered "unregistered IBR."

The drafting team appreciates the suggested alternatives to the use of the Order No. 901 phrase "unregistered IBR" to describe the resources that are intended to be covered. It has considered establishing a defined Glossary term (Unregistered IBR), as well as explicitly defining in the above-the-text requirement language what is an unregistered IBR based on the NERC compliance registry criteria.

The drafting team believes that, with the revised clarification, there is no need to create an additional defined term for "unregistered IBR." Such a term is not likely to aid in understanding, as the definition would be defining the term in the negative relative to other defined terms (i.e., an IBR for which the owner/operator would not be required to register with NERC as a Generator Owner/Generator Operator). The drafting team also determined that replacing the phrase "unregistered IBR" in the requirement text with a more detailed description of what is an "unregistered IBR" that draws from the GO/GOP registry criteria (e.g., "not an IBR BES Facility, not a non-BES inverter based generating resource that either has or contributes 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, and not a DER") would lead to lengthier requirements that are less readable without providing additional clarity. The drafting team believes that the revised footnote is clearer as to the scope of the IBR intended to be covered while maintaining readability.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Nextera supports comments provided by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	

(1) The proposed MOD-032-2 modifications do not to address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models that accurately reflect the behavior of all IBRs).

(2) The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. There is disagreement regarding the enforceability of footnotes, which may leave certain entities vulnerable.

(3) P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

(1) Milestone 3 has been split into three separate projects. Project 2022-02 focuses on MOD-032, which is the uniform framework, Project 2020-06 focuses on the validation and verification of models, and 2021-01 focuses on the system level performance. Some of the FERC directives, while one paragraph, have been split into two projects. The validated and verified directive will be addressed by the 2020-06 MOD-026 drafting team.

(2) Attachment 1 does not create obligations for entities to provide data, but specifies the data items that need to be covered by the PC/TP data reporting procedures and requirements. This includes DER data for situations described in the footnote where there is no registered DP (and NERC has always been very clear the footnotes are part of the standards and fully enforceable). The DT proposal allows the PC/TP flexibility to identify the best responsible entity for their area. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather DER data.

(3) Provision of models consistent with the uniform model framework to Transmission Operators to be utilized for Operations Planning and Real-time Assessments is addressed by the proposed modifications to IRO-010 and TOP-003.	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 901 P104 states "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." Please see the updated TR, which provides some examples of methods on how to complete estimations with little data or no data. While the team understands the importance of accuracy, it is important to have an allowance for estimation when data is not available.	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	

We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 901 P104 states "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." Please see the updated TR, which provides some examples of methods on how to complete estimations with little data or no data. While the team understands the importance of accuracy, it is important to have an allowance for estimation when data is not available.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI and MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI and MRO NSRF.	

Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 901 P104 states "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." Please see the updated TR, which provides some examples of methods on how to complete estimations with little data or no data. While the team understands the importance of accuracy, it is important to have an allowance for estimation when data is not available.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
AZPS supports the following comments submitted by EEI on behalf of its members:	

Requirement 2

EEI does not support Requirement R2, Part 2.1 because this requirement places inappropriate compliance burdens on the TO that they have no practical method of fulfilling without the support of unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While EEI does not dispute that information from these unregistered entities may be needed and could impact BPS reliability, we do not agree that the answer is to place this compliance burden on TOs. Guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DPs. We additionally offer some suggested changes (clean version) to Requirement R2 to add additional clarity:

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1 For unregistered Inverter-based Resource (IBR) data, the responsible TO, whose transmission system these resources are connected, shall develop estimates of the aggregated unregistered IBRs including estimated modeling data. The TO shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations.

2.2 For Distributed Energy Resource (DER) data the responsible DP shall develop estimates of the aggregated DER connected to their distribution systems including aggregated modeling data. The DP shall also include an explanation of the limitations of the aggregated data as provided and the methods used for their estimations.

2.3 For distribution systems that are interconnected to a responsible TO system, where no registered DP exists, the TO shall document all attempts to gather aggregate estimates of DER capacity from the unregistered DP.

2.3.1 If the TO is success in gathering aggregate estimates of DER capacity from the unregistered DP, the data shall be forwarded to the responsible PC and TP so they can assess if the DER capacity on the unregistered DP's distribution system represents a material impact on the BPS.

2.3.1.1 If the PC & TP determines a material impact exists, their findings shall be reported to the ERO for further actions.

2.3.1.2 If the PC & TP determine there is not a material impact, no further actions are required by the responsible TO, unless further actions are requested by the PC & TP.

2.3.2 If the TO is unsuccessful in gathering aggregate estimates of DER capacity from the unregistered DP, they are to report their inability to collect the required data to both the responsible PC and TP, who will report the issue to NERC for further actions.

Attachment 1 Concerns:

EEI offers the following comments and edits (clean version) to Attachment 1 below:

Item 2 – It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for in various modeling scenarios.

Item 9 – TOs are entirely dependent on responsible registered DPs and should therefore be removed from having direct responsibility for Aggregate DER data. Additionally, 9c should be deleted to better align with what DPs are capable of collecting (i.e., aggregate DER data by storage types).

Dynamics Concerns:

Item 5 - It is unclear where large loads connected to transmission systems are accounted for in planning studies. While we agree that DPs are responsible for demand data on distribution systems, it is unclear where other demand data that the LSE previously reported is reported and accounted for various modeling scenarios.

Item 7 – Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR. To address our concerns, we offer the following changes (clean format):

7. Inverter-Based Resource

a. Registered IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control [GO]

b. Aggregated capability of non-registered IBRs connect to the BPS including estimates related to momentary cessation, tripping, Ride-through, and frequency control [TOs]

Item 10 – TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed. To address our concerns, we offer the following changes (clean version):

10. Aggregate Distributed Energy Resource (DER) data

a. Estimates of aggregated DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. [DP, UFLS only DPs]

b. Indication whether DERs are part of any UFLS or UVLS schemes and provide estimates of the affected aggregated capacity on those schemes. [DP, UFLS only DPs]

Footnote concerns:

Footnote 1: EEI does not agree with Footnote 1. Data requirement obligations should be clearly specified within each sub-bullet of each column for both steady-state and dynamics to ensure responsible entities understand their roles.

Footnote 2: EEI suggests the following change to footnote 2 (clean version):

For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. The Distribution Provider is the responsible entity for providing this information, through coordination with the Transmission Owner.

Footnote 4: EEI does not agree that IBRs should be generically identified as storage devices. Instead, Battery Energy Storage System (BESS) should replace IBR in footnote 4 as changed below (clean version):

This includes battery energy storage systems, synchronous condensers, and pumped storage.

Footnote 5: Ambiguous terms like typical should not be included in NERC Reliability Standard. We additionally feel that it should be made clear the limits of TO responsibilities regarding unregistered IBRs as changed below (clean version).

The transmission owner is the responsible entity for collecting and providing aggregate data for unregistered IBRs that are not DERs and directly connected to their portion of the BPS.

Footnote 6: TO and DP have no ability to collect or provide aggregate data for DERs that are not connected directly to their system. If DER data is needed from unregistered DPs to preserve the reliability of the BPS, then those entities should be registered. The following change (clean version) has been provided to clarify what registered DPs are capable of providing under MOD-032:

The Distribution Provider is the responsible entity for collecting and providing aggregate data for DER connected to their distribution system.

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	

AES Indiana supports comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not something we feel is appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 901 P104 states "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation." Please see the updated TR, which provides some examples of methods on how to complete estimations with little data or no data. While the team understands the importance of accuracy, it is important to have an allowance for estimation when data is not available.	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	

· The proposed MOD-032-2 modifications do not to address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models that accurately reflect the behavior of all IBRs).

· The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. There is disagreement regarding the enforceability of footnotes, which may leave certain entities vulnerable.

· P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Milestone 3 has been split into three separate projects. Project 2022-02 focuses on MOD-032, which is the uniform framework, Project 2020-06 focuses on the validation and verification of models, and 2021-01 focuses on the system level performance. Some of the FERC directives, while one paragraph, have been split into two projects. The validated and verified directive will be addressed by the 2020-06 MOD-026 drafting team.

Attachment 1 does not create obligations for entities to provide data, but specifies the data items that need to be covered by the PC/TP data reporting procedures and requirements. This includes DER data for situations described in the footnote where there is no registered DP (and NERC has always been very clear the footnotes are part of the standards and fully enforceable). The DT proposal allows the PC/TP flexibility to identify the best responsible entity for their area. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather DER data.

Provision of models consistent with the uniform model framework to Transmission Operators to be utilized for Operations Planning and Real-time Assessments is addressed by the proposed modifications to IRO-010 and TOP-003.

The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to “develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions” (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a “generic model”, and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO, does not presently maintain an “acceptable model library”, but rather an “unacceptable model library”, and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations

would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) does not support the proposed revisions in MOD-032-2, specifically, R2.1. CEHE believes the Transmission Owner (TO) is not the appropriate registered entity to be responsible for providing estimations of unregistered load.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT is addressing FERC Order 901 that directives "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the	

reliability of the Bulk-Power System. To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."

Attachment 1 does not create obligations for entities to provide data but specifies that data items that need to be covered by the PC/TP data reporting procedures and requirements (and typical functional entities for providing such data). Thus, the DT proposal allows the PC/TP flexibility to identify the best responsible entity for their area rather than mandating a specific functional entity to provide data across the continent. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather DER data.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not agree that enforceable Reliability Standards should be reliant on external documents such as the document titled "ERO Approved Criteria for Acceptable Models" (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. Moreover, the Commission directed NERC "to develop **new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish** for each interconnection a uniform framework with modeling criteria" (emphasis added; FERC Order 901, P161). To better align with FERC Order 901, we offer the following comments and suggested edits in boldface below:

Requirement R1

Our edits are limited to part 1.2 in boldface below:

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1 The data listed in Attachment 1, including the responsible entity for each required item.

1.2 Specifications for the following items for dynamic models submitted in accordance with Attachment 1:

1.2.1 A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.2.2 Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s), or a technical justification for the submission and use of user-written models if such models are permitted.

1.2.3 Criteria for any submitted user-written models including, at a minimum, documentation, and performance criteria to minimize the risk of non-convergence and other issues. The PC's user-written model criteria must be made available to all other TP/PCs within the Interconnection for review and comment, and approval where the usage of the user-written model represents a shared impact.

1.3 Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.3.1 Data format;

1.3.2 Level of detail to which equipment shall be modeled;

1.3.3 Case types or scenarios to be modeled; and

1.3.4 A schedule for submission of data at least once every 13 calendar months.

1.4 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

Footnote 1: For example, the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases.

Requirement R2

EEI does not support Requirement R2, part 2.1 because this requirement places compliance obligations on the TO that they have no practical method of fulfilling without the support of the unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While it is unclear how DER data from unregistered entities might impact BPS reliability, TO will be limited in their ability to fulfill their compliance obligations without the direct assistance and participation for unregistered DPs. To address this concern, guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DP does not provide the data requested by

the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DPs. We additionally offer some suggested boldface edits to Requirement R2 to add additional clarity:

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1 For unregistered Inverter-based Resource (IBR) data, the responsible TO, whose transmission system these resources are connected, shall develop estimates of the aggregated unregistered IBRs including estimated modeling data. The TO shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations.

2.2 For Distributed Energy Resource (DER), the responsible registered DP, whose distribution system these resources are connected, shall develop estimates of the aggregated unregistered DERs including estimated modeling data. The DP shall also include with the data an explanation of the limitations of the aggregated data, as provided, and the methods used to develop their estimations. Upon completion, the data shall be sent to the responsible TO for collection and distribution to the responsible PC/TP.

2.3 For unregistered DPs the TO shall request DER data consistent with 2.2.

2.3.1 Where no data is provided by the unregistered DP, the TO shall develop an estimate of the DERs connected to the unregistered DP system. The TO shall also develop an explanation of the limitations of the aggregated data provided and the methods used for their estimations for distribution to the responsible PC/TP.

Attachment 1 Concerns: EEI offers the following comments and suggested edits (in boldface) to Attachment 1 below:

Item 2 – EEI requests clarification whether DPs are a suitable replacement for the LSE. While we agree that DPs are fully capable of providing demand data on distribution systems, they have no ability to provide load data on transmission systems.

Item 9 – EEI is of the opinion that 9c should be deleted because we do not agree that DER data by type is needed by the PC/TP. Additionally, given TOs can only supply DER rough estimate of aggregate DERs on unregistered systems, they have no ability to distinguish DERs by type.

Dynamics Concerns

Item 5 - EEI requests clarification whether DPs are a suitable replacement for the LSE. While we agree that DPs are fully capable of providing demand data on distribution systems, they have no ability to provide load data on transmission systems.

Item 7 – Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR. To address our concerns, we offer the following boldface edits to Item 7:

7. Inverter-Based Resource

a. Registered IBR capabilities related to momentary cessation, tripping, Ride-through, and frequency control **[GO]**

b. **Aggregated capability of non-registered IBRs connect to the BPS including estimates related to momentary cessation, tripping, Ride-through, and frequency control [TOs]**

Item 10 –EEI suggests clarifying TOs are only responsible for Aggregated DER data when there is no registered DP and they have no ability to assess UFLS impact from DERs unless provided by the unregistered DP. Additionally, UFLS only DPs should be added to Item 10

10. Aggregate Distributed Energy Resource (DER) data

a. **Estimates of aggregated** DER capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those capabilities for modeling purposes. **[DP, UFLS only DPs, TO (for non-registered DPs)]**

b. **I**ndication whether DER**s are part of any** UFLS or UVLS **schemes and provide estimates of the affected aggregated capacity on those schemes**. **[DP, UFLS only DPs]**

Footnote concerns

Footnote 1: EEI does not agree with Footnote 1. Data requirement obligations should be clearly specified within each sub-bullet of each column for both steady-state and dynamics to ensure responsible entities understand their roles.

Footnote 4: EEI does not agree that IBRs should be generically identified as storage devices. Instead, Battery Energy Storage System (BESS) should replace IBR in footnote 4. Note the following boldface edits:

This includes **battery energy storage systems**, synchronous condensers, and pumped storage.

Footnote 5: Ambiguous terms like typical should not be included in NERC Reliability Standard. We additionally feel that it should be made clear the limits of TO responsibilities regarding unregistered IBRs.

The transmission owner is the responsible entity for collecting and providing **aggregate** data for unregistered IBRs that are not DERs **and directly connected to their portion of the BPS.**

Footnote 6: TO and DP have no ability to collect aggregate data for DERs that are not connected directly to their system. Where DER data is needed from unregistered DPs to preserve the reliability of the BPS, then the TO should provide an estimate of the DERs connected to the unregistered DP system based on information provided by the unregistered DP or consistent with aggregated DER levels provided by other DPs connected to their system. The following boldface edits have been provided to clarify what TO are capable of providing under MOD-032:

The Distribution Provider is the responsible entity for collecting and providing **aggregate** data for DER connected to **their distribution** system. **Where no registered DP exists, the TO shall develop estimates on aggregated DER levels based on information obtained from the unregistered DP or consistent with DER levels provided by other DPs connected to their system.**

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the DTs updated edits to MOD-032-2.

The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include

this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions. The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	
Comment	
SIGE supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

No. *Reliability Standards to Address Inverter-Based Res.,* Order No. 901, 185 FERC ¶ 61,042 (2023) ("Order 901") calls for two different terms for purposes of determining the data and modeling of Inverter-Based Resources ("IBRs") whose owners are not registered and subject to compliance as Category 2 Generator Owners/Generator Operators (GO/GOPs): (1) "unregistered IBRs," whose data is to be reported individually and (2) IBR-Distributed Energy Resources ("IBR-DERs"), whose data is to be reported (or estimated) in the aggregate. Order 901 explicitly differentiates between "unregistered IBRs," which it describes as "IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards," and "IBR-DERs," which it describes as "IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk Power System." *Id.* P 4 n.14. The two draft standards address both types of IBRs but do so in ways that fail to achieve FERC's stated purpose of addressing the failure of existing standards to accurately account for the different way that IBRs respond to disturbances, as compared to synchronous generation. *Id.* P 37 (emphasis added) (footnotes omitted). *See also id.* PP 2-4, 50:

Data that *accurately* represents IBRs is necessary to properly plan for, operate, and analyze IBR performance on the Bulk-Power System. Without data that accurately represents all IBRs, planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities are not able to develop system models that accurately account for the behavior of IBRs on their system, nor are they able to facilitate the analysis of Bulk-Power System disturbances.

While there may be other issues with the proposed use of these terms, these comments focus on two flaws:

(1) Defining the scope of the unregistered IBRs to be reported and modeled by use of a footnote referring to those IBRs connected to the Bulk-Power System ("BPS"), a vague term that is for FERC to define, rather than providing a clear cutoff consistent with the FERC-approved GO/GOP Category 2 registry criteria or the successfully balloted GO/GOP Category 2 Glossary definition. Such usage is not appropriate to determine the scope of what is to be covered by enforceable standards, and the resulting imprecision will invite double counts and gaps that will prevent the standards from achieving Order 901's reliability purposes.

(2) Instead of restricting the provision of data and modeling to IBR-DERs as Order 901 directs, relying on a DER definition that encompasses both IBR and non-IBR resources that are connected to the distribution system. This failure to have a definition focused solely on IBR-DERs threatens to undermine the express objective of Order 901 to accurately account for the behavior of IBRs. While the addition of Item 9.c under the "steady-state" column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards (*see, e.g.,* Item 10 under "dynamics" of that same Attachment; footnote 1 of draft MOD-033-3) invites confusion that could also carry over to other standards that are intended to reflect and account for the particular characteristics of IBRs.

Further details on concerns regarding these two definitions are provided in Questions 4 and 7.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Thank you for your comment. Please see the DTs updated edits to MOD-032-2.

The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO, does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-

032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.	
Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	

LCRA TSC supports the following comments submitted by EEI on behalf of its members:

Requirement 2
EEI does not support Requirement R2, Part 2.1 because this requirement places inappropriate compliance burdens on the TO that they have no practical method of fulfilling without the support of unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While EEI does not dispute that information from these unregistered entities may be needed and could impact BPS reliability, we do not agree that the answer is to place this compliance burden on TOs. Guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DP.

Attachment 1 concerns:
Steady State Item 9: TOs are entirely dependent on responsible registered DPs and should therefore be removed from having direct responsibility for Aggregate DER data.

Dynamics Item 7: Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR.

Dynamic Item 10: TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed.

Likes 0	
Dislikes 0	

Response

Please see the DT's response to EEI.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
Constellation does not agree with the changes made and feels it creates ambiguity for Regional Entities on estimated unregistered IBR entities. Specifically, in 2.1 a caveat for data requirements for unregistered units is provided which allows Regional Entities to provide estimates of data. This is asking for data that would not be relevant for models if it is not accurate data and could call for ambiguity between regions on the amount of data required. Constellation suggests striking the term unregistered to reduce ambiguity. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. The DT is addressing FERC Order 901 that directives "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the reliability of the Bulk-Power System. To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."

Joseph Scott - Lower Colorado River Authority - 5	
Answer	No
Document Name	

Comment
LCRA supports the following comments submitted by EEI on behalf of its members: Requirement 2 EEI does not support Requirement R2, Part 2.1 because this requirement places inappropriate compliance burdens on the TO that they have no practical method of fulfilling without the support of unregistered DPs. Moreover, the TOs played no part in interconnecting the DERs on unregistered DP systems, nor do they have any ability to compel those entities to provide the information needed. While EEI does not dispute that information from these unregistered entities may be needed and could impact BPS reliability, we do not agree that the answer is

to place this compliance burden on TOs. Guidance could be developed to clarify exactly what must be provided by the TO, including the basis for DER estimates whenever an unregistered DPs does not provide the data requested by the TO. However, if unregistered DPs are having a material impact on the Reliability of the BPS, consideration should be given to adjusting the registration criteria for DP.

Attachment 1 concerns:

Steady State Item 9: TOs are entirely dependent on responsible registered DPs and should therefore be removed from having direct responsibility for Aggregate DER data.

Dynamics Item 7: Item 7 should be made clear that TOs are only responsible for supplying Aggregate data for Unregistered IBR.

Dynamic Item 10: TOs should be removed from Item 10 because they are not the appropriate entity to collect DER data on distribution systems. EEI also notes that UFLS only DPs were not identified as having responsibilities for providing aggregated DER data on their systems or DER impacts to UFLS system they have installed.

Likes 0	
Dislikes 0	

Response

Please see the DT's response to EEI.

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

Constellation does not agree with the changes made and feels it creates ambiguity for Regional Entities on estimated unregistered IBR entities. Specifically, in 2.1 a caveat for data requirements for unregistered units is provided which allows Regional Entities to provide estimates of data. This is asking for data that would not be relevant for models if it is not accurate data and could call for ambiguity between regions on the amount of data required. Constellation suggests striking the term unregistered to reduce ambiguity.

Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT is addressing FERC Order 901 that directives "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the reliability of the Bulk-Power System. To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company has voted "yes" on previous ballots related to MOD-032 modifications and supports most of the standard revisions. However, significant changes to NERC's external document "ERO Approved Criteria for Acceptable Models document" since the last MOD-032 revision, specifically the inclusion of criteria modifications that could impact a Registered Entity's compliance, highlight our significant concern with the new MOD-032 revisions.	

There are simple changes that NERC can make to MOD-032 to garner our support, and specifically that includes moving any criteria in the "ERO Approved Criteria for Acceptable Models document" within the standard and converting the external model reference to a "ERO Approved Acceptable Models list" consistent with FERC 901 requirements. Additional comments are included in question 6.

Southern Company additionally recommends the minor revisions below for enhanced clarity:

- On Requirement 1 – add the word "Functional" in front of entities to make it clear the standard is referencing NERC Functional Entities.
- On Requirement 2 – add the word "Functional" in front of entities to make it clear the standard is referencing NERC Functional Entities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The DT added functional in front of entities through MOD-032 where appropriate.

The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a “generic model”, and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an “acceptable model library”, but rather an “unacceptable model library”, and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered

part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The standard should also address data for DERs where there is no associated registered DP. P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No

Document Name	
Comment	
2 years implementation to collect all DERs on the distribution system is likely not feasible considering the standard includes rooftop solar and other types of DERs connected behind the meters. The standard further requires the dynamics modeling data that is often not available for DERs and it would likely take significant time for Distribution Providers to gather and develop these modeling data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires all standard creation and modifications to be in effect by 2030. For milestone 4 to meet this FERC directed requirement, this is the most time that can be allotted for MOD-032 to allow the next project time to meet the FERC directive.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_ATC.docx
Comment	
Please see question 1 comments (highlighted) in attached document.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. MOD-032 is in alignment with project 2024-01. GO/GOP category 1 and 2 will be in effect by the time MOD-032-2 becomes effective, and therefore, nothing additional is needed to be added to the applicability section of MOD-032.	

The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO, does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would

advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC Staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	No

Document Name	
Comment	
SRP supports the comments of WAPA and Bonneville Power.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WAPA and Bonneville Power.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

The NAGF would like to see MOD-032 modified to require the TP and PC to request data from those entities they want data from, rather than expect all other entities to track what the TP and PC are requiring. With the addition of Generator Owners that may or may not be interconnected to any NERC-registered entity, the TP and PC need to actively engage with these entities to ensure the TP and PC are able to get the best data possible and provide feedback as to what is needed/acceptable, etc. Additionally, the NAGF supports the comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. MOD-032 has been modified to have the TP and PC identify the entity responsible for providing the data items listed in Attachment 1. GOs are an applicable functional entity for MOD-032 and are obligated provide data as specified by the TP and PC. In addition, please see the DT's response to EEI.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Daniel Gacek - Exelon - 1, Group Name Exelon	

Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
• The proposed MOD-032-2 modifications do not address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models accurately reflect the behavior of all IBRs). • The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. • P141 directs NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.	

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

(1) Milestone 3 has been split into three separate projects. Project 2022-02 focuses on MOD-032, which is the uniform framework, Project 2020-06 focuses on the validation and verification of models, and 2021-01 focuses on the system level performance. Some of the FERC directives, while one paragraph, have been split into two projects. The validated and verified directive will be addressed by the 2020-06 MOD-026 drafting team.
(2) Attachment 1 does not create obligations for entities to provide data but specifies the data items that need to be covered by the PC/TP data reporting procedures and requirements. This includes DER data for situations described in the footnote where there is no registered DP (and NERC has always been very clear the footnotes are part of the standards and fully enforceable). The DT proposal allows the PC/TP flexibility to identify the best responsible entity for their area. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather DER data.
(3) Provision of models consistent with the uniform model framework to Transmission Operators to be utilized for Operations Planning and Real-time Assessments is addressed by the proposed modifications to IRO-010 and TOP-003.

Colin Chilcoat - Invenergy LLC - 6

Answer	No
Document Name	

Comment

Invenergy does not agree with the revisions to MOD-032-2. Specifically, MOD-032-2 is not self-contained and requires entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that the "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves. Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use. In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases. The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC, as the ERO, does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901. To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team

believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns. The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions. The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	

Comment
Invenergy does not agree with the revisions to MOD-032-2. Specifically, MOD-032-2 is not self-contained and requires entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that the "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves. Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use. In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to “develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions” (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases. The drafting team considered that many entities have a different understanding for what is a “generic model”, and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an “acceptable model library”, but rather an “unacceptable model library”, and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations

would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.	
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 effort put forth by the SDT to address the directives of FERC Order 901; however, we have concerns with the data collection burden being placed on responsible entities (as identified in Requirement R1 Part 1.1). Much of the industry is already operating with limited resources, and many (if not most) entities are currently short-staffed. This is particularly true for smaller entities such as electric cooperatives. In short, we are not convinced that this level of data collection is a cost-effective approach to improving grid reliability and reducing risk. Lastly, we would like to point out a minor discrepancy between the “redline” and “clean” versions of this draft of MOD-032-2. Requirement R2 Part 2.1 in the “clean” version is missing a portion of the language contained in the “redline” version. The phrase “…Energy Resource (DER) data, the responsible entity shall estimate the modeling…” do not appear in the “clean” version of Part 2.1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT is addressing FERC Order No. 901 P104 states "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation.” Please see the updated TR, which provides some examples of methods on how to	

complete estimations with little data or no data. While the team understands the importance of accuracy, it is important to have an allowance for estimation when data is not available. Without entities providing equally effective and efficient method proposals, this is where the team landed as the best option to address the FERC directives.

The DT will ensure the next versions posted line up correctly. Thank you for bringing this to our attention.

Colten Mitchell - Indiana Municipal Power Agency - 4	
Answer	No
Document Name	
Comment	

No. *Reliability Standards to Inverter-Based Res.,* Order No. 901, 185 FERC ¶ 61,042 (2023) ("Order 901") calls for two different terms for purposes of determining the data and modeling of Inverter-Based Resources ("IBRs") whose owners are not registered and subject to compliance as Category 2 Generator Owners/Generator Operators (GO/GOPs): (1) "unregistered IBRs," whose data is to be reported individually and (2) IBR-Distributed Energy Resources ("IBR-DERs"), whose data is to be reported (or estimated) in the aggregate. Order 901 explicitly differentiates between "unregistered IBRs," which it describes as "IBRs connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards," and "IBR-DERs," which it describes as "IBRs connected to the distribution system that in the aggregate have a material impact on the Bulk Power System." *Id.* P 4 n.14. The two draft standards address both types of IBRs but do so in ways that fail to achieve FERC's stated purpose of addressing the failure of existing standards to accurately account for the different way that IBRs respond to disturbances, as compared to synchronous generation. *Id.* P 37 (emphasis added) (footnotes omitted). *See also id.* PP 2-4, 50:

Data that *accurately* represents IBRs is necessary to properly plan for, operate, and analyze IBR performance on the Bulk-Power System. Without data that accurately represents all IBRs, planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities are not able to develop system models that accurately account for the behavior of IBRs on their system, nor are they able to facilitate the analysis of Bulk-Power System disturbances.

While there may be other issues with the proposed use of these terms, these comments focus on two flaws:

(1) Defining the scope of the unregistered IBRs to be reported and modeled by use of a footnote referring to those IBRs connected to the Bulk-Power System ("BPS"), a vague term that is for FERC to define, rather than providing a clear cutoff consistent with the FERC-approved

GO/GOP Category 2 registry criteria or the successfully balloted GO/GOP Category 2 Glossary definition. Such usage is not appropriate to determine the scope of what is to be covered by enforceable standards, and the resulting imprecision will invite double counts and gaps that will prevent the standards from achieving Order 901's reliability purposes.

(2) Instead of restricting the provision of data and modeling to IBR-DERs as Order 901 directs, relying on a DER definition that encompasses both IBR and non-IBR resources that are connected to the distribution system. This failure to have a definition focused solely on IBR-DERs threatens to undermine the express objective of Order 901 to accurately account for the behavior of IBRs. While the addition of Item 9.c under the "steady-state" column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards (*see, e.g.,* Item 10 under "dynamics" of that same Attachment; footnote 1 of draft MOD-033-3) invites confusion that could also carry over to other standards that are intended to reflect and account for the particular characteristics of IBRs.

Further details on concerns regarding these two definitions are provided in Questions 4 and 7.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Thank you for your comment. Please see the DTs updated edits to MOD-032-2.

The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions"

(P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	
Southwest Power Pool abstains from the response to this question. The ERO Approved Criteria for Acceptable Models document referenced in the proposed Requirement R1, Part 1.2 establishes some common-sense usability requirements, but it is unclear how it might be interpreted and enforced. For example, if an auditor determines a model manual is unacceptable in the course of a compliance engagement, it is unclear which entity would be considered to have violated the	

standard: the model submitter, or the planner that accepted the model. If a model and its associated documentation are deemed acceptable by the PC and TP, the model should be considered acceptable.

Furthermore, the usability requirements identified under Chapter 2 within the Usability Requirements section (pgs. 3-4) of the document are mostly administrative requirements that address model documentation. The usability requirements identified in Chapter 5 within the Technical Rationale section (pg. 8) are arguably more important for actually being able to perform simulations, but it is not clear how enforceable they would be. Ultimately, it seems like a violation of the Criteria for Acceptable Models document could be better addressed as an identified technical concern under Requirement R3 and most of the substantive parts of the criteria document could be consolidated into the existing, separate Technical Rationale to detail examples of issues that would need to be addressed under Requirement R3. Thus, the ISO/RTO Council (IRC) Standards Review Committee (SRC) suggests that the proposed Requirement R1, Part 1.2 be deleted and a new Part 1.4 be added that reads as follows:

"1.4. Specifications of the following items for dynamic model submissions:

1.4.1. A list of unacceptable models[1], which are not to be submitted unless no alternative model is available;

1.4.2. Required submission of standard library models recognized by the software utilized to create the interconnection-wide case(s) and/or user-written models; and

1.4.3. Criteria for any submitted user-written models, including, at a minimum, model documentation and instructions for model setup and use to minimize the risk of non-convergence and other issues.

Footnote 1: For example, data requirements and reporting procedures may point to the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases."

The proposed language above provides explicit flexibility for PC/TP to require generic models, user-defined models, or both. In conjunction with Requirement R3, this addresses the FERC directives in a more enforceable and easily understood manner than the currently proposed use of a separate ERO criteria document.

Additionally, proposed footnote 1 (which would become footnote 2 if the Part 1.4 language proposed above is adopted) within Requirement R2, Part 2.1 should be modified to read as follows: *"As used in this standard, the phrase 'unregistered IBR' refers to an IBR that is not a DER*

and does not meet mandatory NERC registration criteria." The drafting team has already acknowledged the ambiguities associated with attempting to define DER based on "connection to the BPS." Using the concept of BPS connection here introduces those same ambiguities.

Finally, Requirement R3, Part 3.1 should be modified to read as follows: *"Provide either updated data or an explanation with a technical basis for maintaining the current data that resolves the technical concern."*

This added language is necessary to ensure technical concerns are adequately addressed. For example, if the technical concern is suspicious data, a technical basis for maintaining current data may be acceptable in some circumstances but would not resolve the underlying issue if the model crashes or does not initialize.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Supporting Document to the draft MOD-

032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the RSTC. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.	
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	
Please see the DT's response to EEI.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

The use of aggregated, generic data to model IBR's may do more harm than good. Accurate data is required to reliably meet the FERC order. Perhaps generic data is the first step but caution must be taken to avoid consequential, incorrect analysis.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires in P104 "[r]ecognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the reliability of the Bulk-Power System. To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters." Based on the directive to provide estimates if are unable to gather data, the team added a requirement to ensure an estimation is completed should the respective entity not be able to gather data needed.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

For this question, 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	
Please see the DT's response to ISO/RTO SRC.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
ISO New ENgland signs onto all of the ISO/RTO Standards Review Committee (SRC) Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to ISO/RTO SRC.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
As noted by IRC, SPP supports the following portion of the response:	

The ERO Approved Criteria for Acceptable Models document referenced in the proposed Requirement R1, Part 1.2 establishes some common-sense usability requirements, but it is unclear how it might be interpreted and enforced. For example, if an auditor determines a model manual is unacceptable in the course of a compliance engagement, it is unclear which entity would be considered to have violated the standard: the model submitter, or the planner that accepted the model. If a model and its associated documentation are deemed acceptable by the PC and TP, the model should be considered acceptable.

Furthermore, the usability requirements identified under Chapter 2 within the Usability Requirements section (pgs. 3-4) of the document are mostly administrative requirements that address model documentation. The usability requirements identified in Chapter 5 within the Technical Rationale section (pg. 8) are arguably more important for actually being able to perform simulations, but it is not clear how enforceable they would be. Ultimately, it seems like a violation of the Criteria for Acceptable Models document could be better addressed as an identified technical concern under Requirement R3 and most of the substantive parts of the criteria document could be consolidated into the existing, separate Technical Rationale to detail examples of issues that would need to be addressed under Requirement R3. Thus, the ISO/RTO Council (IRC) Standards Review Committee (SRC) suggests that the proposed Requirement R1, Part 1.2 be deleted and a new Part 1.4 be added that reads as follows:

"1.4. Specifications of the following items for dynamic model submissions:

*1.4.1. A list of unacceptable models{C}**[1]**, which are not to be submitted unless no alternative model is available;*

1.4.2. Required submission of standard library models recognized by the software utilized to create the interconnection-wide case(s) and/or user-written models; and

1.4.3. Criteria for any submitted user-written models, including, at a minimum, model documentation and instructions for model setup and use to minimize the risk of non-convergence and other issues.

Footnote 1: For example, data requirements and reporting procedures may point to the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases."

The proposed language above provides explicit flexibility for PC/TP to require generic models, user-defined models, or both. In conjunction with Requirement R3, this addresses the FERC directives in a more enforceable and easily understood manner than the currently proposed use of a separate ERO criteria document.

Additionally, proposed footnote 1 (which would become footnote 2 if the Part 1.4 language proposed above is adopted) within Requirement R2, Part 2.1 should be modified to read as follows: *"As used in this standard, the phrase 'unregistered IBR' refers to an IBR that is not a DER and does not meet mandatory NERC registration criteria."* The drafting team has already acknowledged the ambiguities associated with attempting to define DER based on "connection to the BPS." Using the concept of BPS connection here introduces those same ambiguities.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to ISO/RTO SRC.	
Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	

TXNM agrees with the comments made by EEI, in addition:

1. The proposed MOD-032-2 modifications do not to address the FERC Order 901 directive on P78 and P161 regarding that the submitted model(s) should accurately reflect the IBR behaviors. The standard should explicitly require that submitted models be verified and validated to ensure they accurately reflect IBR behaviors, aligning with MOD-026 (ensuring that the approved industry IBR models that accurately reflect the behavior of all IBRs).
2. The standard should also include a requirement to address data for DERs where there is no associated registered Distribution Provider (DP), rather than relying solely on a footnote. There is disagreement regarding the enforceability of footnotes, which may leave certain entities vulnerable.
3. P141 direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs. Models created in MOD-032-2 must be provided to Transmission Operators to be utilized for Operations Planning and Real-time Assessments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

(1) Milestone 3 has been split into three separate projects. Project 2022-02 focuses on MOD-032, which is the uniform framework, Project 2020-06 focuses on the validation and verification of models, and 2021-01 focuses on the system level performance. Some of the FERC directives, while one paragraph, have been split into two projects. The validated and verified directive will be addressed by the 2020-06 MOD-026 drafting team.
(2) the TP/PC will create their process that requires DER data and will confirm the appropriate entity when no associated registered DP is available per R1. The footnote is not attempting to create a requirement in this case, but provide guidance on what entity should typically be considered responsible.
(3) Provision of models consistent with the uniform model framework to Transmission Operators to be utilized for Operations Planning and Real-time Assessments is addressed by the proposed modifications to IRO-010 and TOP-003.

Michael Goggin - Grid Strategies LLC - 5

Answer	No
Document Name	

Comment

Consistent with FERC's Order 901 directive to consider data sharing requirements for transmission owners to provide data to generators, MOD-032-2 should include a requirement for transmission owners to provide data to generator owners and operators to support accurate modeling and performance, e.g., short circuit data, grid data for offshore wind, information on other power electronic devices around the IBR plant, and voltage harmonics. In many cases this transmission provider data is necessary for generator owners to be able to determine generator settings and comply with MOD-032-2. The Consideration of FERC Order 901 Directives document argues that such a requirement is unnecessary as processes exist for obtaining that data, though in many regions they do not or are inadequate.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The DT discussed and carefully considered P77 from the FERC Order 901. Ultimately, the team concluded that this issue is most appropriately addressed through processes that exist outside of NERC reliability standards and concurs with the suggestion in P77 that these processes are largely already in place. Transmission Owners, bound by confidentiality restrictions, may be unable to share certain information, such as details about nearby facilities (complicating development and enforcement of a NERC requirement and likely reducing the envisioned effectiveness for such a requirement). Further, adding a requirement within MOD-032 for data flows to the Generator Owner does not seem aligned with the purpose of MOD-032 since Generator Owners are not the entities developing interconnection base cases and the absence of this specific requirement does not prevent facility owners from providing models in accordance with MOD-032.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
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; John Nierenberg, 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	

Tacoma Power concurs that the proposed MOD-032 modifications address FERC Order 901 and appreciates the explanation provided in the technical rationale as to when the SDT decided to expand beyond the FERC directive. This additional explanation helped explain what changes directly supported the directives versus those changes that were added as improvements. For example, explaining why both synchronous and asynchronous resources were included in the DER definition, even though the FERC directive only mentioned IBR-DERs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT discussed and carefully considered P77 from the FERC Order 901. Ultimately, the team concluded that this issue is most appropriately addressed through processes that exist outside of NERC reliability standards and concurs with the suggestion in P77 that these processes are largely already in place. Transmission Owners, bound by confidentiality restrictions, may be unable to share certain information, such as details about nearby facilities (complicating development and enforcement of a NERC requirement and likely reducing the envisioned effectiveness for such a requirement). Further, adding a requirement within MOD-032 for data flows to the Generator Owner does not seem aligned with the purpose of MOD-032 since Generator Owners are not the entities developing interconnection base cases and the absence of this specific requirement does not prevent facility owners from providing models in accordance with MOD-032.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
MRO recommends revising R2.1 to avoid use of the term "unregistered Inverter-based Resource" in R2, part 2.1. The current wording is inconsistent with the ERO's current practice of using "registered" to refer to entities and not equipment, Facilities, or resources owned by entities.	
Likes 0	

Dislikes 0	

Response

Thank you for your comment. Requirement R2 Part 2.1 is addressing FERC Order 901 P104, which states: "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the reliability of the Bulk-Power System. To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters." FERC continues to explain in P 107: "We believe that requiring transmission owners and distribution providers to collect required data for unregistered IBRs, and IBR-DERs in the aggregate, will result in greater consistency than the piecemeal approach proposed by Indicated Trade Associations, in which some data for unregistered IBRs and IBR-DERs in the aggregate would also be provided by registered generator owners and operators. Further, we believe that transmission owners and distribution providers are in a better position to collect and estimate required data for unregistered IBRs and IBR-DERs in the aggregate that are directly connected to their respective areas than balancing authorities. We anticipate that the need for estimated data for unregistered IBRs connected to the Bulk-Power System, as opposed to actual data, and thus the burden of collecting such data, will decrease over time due to the model provision requirements in the pro forma LGIP and pro forma SGIP, as adopted in Order No. 2023,6 and the ongoing NERC activities to register IBR generator owners and operators. As transmission providers modify their interconnection agreements in compliance with Order No. 2023, we expect that the need to estimate

[6] Order No. 2023, 184 FERC ¶ 61,054 at P 1659 (revising Attachment A to Appendix 1 of the *pro forma* LGIP and Attachment 2 of the *pro forma* SGIP to require each interconnection customer requesting to interconnect a non-synchronous generating facility to submit to the transmission provider specified modeling information).

data will decrease because validated models for smaller sized resources will begin to be submitted to transmission providers with interconnection requests under the Commission's pro forma SGIP. NERC's registration of previously unregistered IBRs should result in more IBRs providing data and validated models pursuant to applicable Reliability Standards." It is the DT's understanding that entities at a minimum can request data for unregistered IBRs, and if nothing is provided, the respective entity, identified by the PC and TP, can estimate.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) question 1.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
It looks like in MOD-032, in the Compliance section 1.2 the word "directive" should be "directed."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The word "directive" has been updated to "directed" in compliance section 1.2.	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
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	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
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; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
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; Kris Kirkegaard, 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	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	
Document Name	
Comment	
The proposed changes allow the Planning Coordinators to add additional detail to the modeling requirements to ensure DER data is modeled to allow for appropriate system planning studies	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EPRI agrees with the intent of the proposed MOD-032-2 modifications but abstains from answering with "Yes" or "No" to this question.

EPRI research informs the potential need and feasibility of changes to MOD-032-2, see for example:

- *Transmission Planning Considerations for DER Wholesale Market Participation: An EPRI FO2222 Phase 1 Collaborative Report.* EPRI. Palo Alto, CA: 2022. 3002020592.
- *EPRI Technology Transfer to NERC SPIDER Working Group: Informing NERC Stakeholder Discussions and Publications on System Planning Impacts of Distributed Energy Resources in the Years 2022-2024.* EPRI. Palo Alto, CA: 2025. 3002031525.
    - Including the reports listed under “Related Material” on that page.

EPRI worked with vendors of fundamental-frequency phasor-domain transient (PDT) modeling domain transmission planning software since 2019 and all of them have implemented the so-called *Aggregate DER (DER_A) Model* in their positive-sequence phasor domain tools:

- *The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies: 2019 Update.* EPRI. Palo Alto, CA: 2019. 3002015320.

EPRI (and other entities) have tested and applied the DER_A model extensively, and we published the following report in 2021:

- Analyzing the Impact of Aggregated DER Behavior on Bulk Power System Performance – A Summary of Three Case Studies. EPRI. Palo Alto, CA: 2021. 3002019445.

Likes	0	

Dislikes 0	

Response
Thank you for your comments and additional information.

2. Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system? If not, what entity would be in a better position to provide that data and add justification?	
Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	
TXNM Energy feels that the Resource Planner is in a better position to aggregate DER information than the transmission owner. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. If unregistered DER data is critical to the reliability of the BPS, then unregistered DPs that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered DP between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No

Document Name	
Comment	
The responsibility of TOs to gather DER data from unregistered DP's places a compliance risk on them. Unregistered entities have no compliance obligation to provide the necessary data, making it challenging for TOs to fulfill their responsibilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application. Relevant to this discussion, Order No. 901 used the phrase "registered IBR" to refer to IBRs registered with NERC (or which would be registered pursuant to the Commission's directives in Registration of Inverter-based Resources, 181 FERC ¶ 61,124 (2022) and therefore subject to the Reliability Standards, and the phrase "unregistered IBR" to refer to 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). It is important to note that Order No. 901 predated the changes NERC made to the Rules of Procedure to ensure that the owners and operators of such IBR resources would be registered with NERC for mandatory compliance purposes. NERC does not register IBRs as resources, but rather the owners of such resources based on the registry criteria for Generator Owner and Generator Operator. There are two categories of each: owners and operators of BES Facilities (category 1 GOs/GOPs); and owners and operators of 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 (category 2 GOs/GOPs).	

In Order No. 901 parlance, ownership or operation of IBR resources meeting these criteria would require owner/operator registration, and therefore would be considered “registered IBRs”.

In Order No. 901 parlance, ownership or operation of IBR resources that do not meet these criteria but are connected to a transmission system (i.e., are not Distributed Energy Resources) would not require owner/operator registration, and therefore would be considered “unregistered IBR.”

The drafting team appreciates the suggested alternatives to the use of the Order No. 901 phrase “unregistered IBR” to describe the resources that are intended to be covered. It has considered establishing a defined Glossary term (Unregistered IBR), as well as explicitly defining in the above-the-text requirement language what is an unregistered IBR based on the NERC compliance registry criteria.

The drafting team believes that, with the revised clarification, there is no need to create an additional defined term for “unregistered IBR.” Such a term is not likely to aid in understanding, as the definition would be defining the term in the negative relative to other defined terms (i.e., an IBR for which the owner/operator would not be required to register with NERC as a Generator Owner/Generator Operator).
The drafting team also determined that replacing the phrase “unregistered IBR” in the requirement text with a more detailed description of what is an “unregistered IBR” that draws from the GO/GOP registry criteria (e.g., “not an IBR BES Facility, not a non-BES inverter based generating resource that either has or contributes 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, and not a DER”) would lead to lengthier requirements that are less readable without providing additional clarity.

The drafting team believes that the revised footnote is clearer as to the scope of the IBR intended to be covered while maintaining readability.

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	
Please see the DT's response to EEI.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The Transmission Owner (TO) is not always the most suitable entity to collect and provide data for Distributed Energy Resources (DER), particularly in instances where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. If unregistered DER data is critical to the reliability of the BPS, then unregistered DPs that	

have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria such as DP – DER, similar to DP-UFLS.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI. Additionally, TPs and PCs may have more authority to obtain data from unregistered entites than the connected TOs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI.	

Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The unregistered entity is the best entity to request data from, and there is no prohibition to requesting data from unregistered entities. The NAGF notes this language in TOP-003-5 "…including non-BES data and external network data as deemed necessary by the Transmission Operator." This does not appear to limit the TOP to only information from registered entities. It appears to say that the TOP should ask for the	

data it needs, even if the data is not BES data. The TP and PC should be expected to do the same, however, they should not be held accountable for the accuracy of estimates provided whenever the unregistered DPs decline a request for data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	No

Document Name	
Comment	
SRP supports the following comments submitted by EEI on behalf of its members.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC does not agree that the TO should be held responsible for collecting or providing data on DERs where they have no authority and ability to collect data, and have not interconnected those resources. If this data is necessary to analyze and determine the reliability of the BPS then the unregistered DPs that interconnect DER resources should be registered.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood	

through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
The entity which the DER is directly interconnected to.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Joseph Scott - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA supports EEI comments which state:	

EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	No
Document Name	
Comment	

LCRA TSC supports EEI comments which state: EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	
Comment	

SIGE supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not dispute that TOs are the only registered entity available to provide data from unregistered DPs. However, they are limited in their ability to obtain and provide this data because they have no ability to compel unregistered DPs to provide such data. Moreover, the TO should be viewed simply as a conduit for DER data provided by the unregistered DPs and should not be held accountable for the accuracy of estimates provided whenever the unregistered DPs decline a TO's request for data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	

In addition, the Commission acknowledged in FERC order 901 P103: “we find persuasive the comments explaining that certain data may be challenging or infeasible for the transmission owner or distribution provider to obtain. We recognize that there may be limitations on the ability of certain transmission owners to provide all data about unregistered IBRs that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System. Likewise, there may be limitations on the ability of certain distribution providers to provide all data about IBR-DERs in the aggregate that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System. We therefore modify the NOPR proposal, as discussed below.” The Commission Provides a resolution on how to gather the data should it not be received through P 104 stating: “Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters’ concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve the reliability of the Bulk-Power System. To support this data collection, we further direct NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters.” This expresses the importance that entities should be aware of unregistered IBR connected to the grid for reliability purposes.

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE believes the TO is not the appropriate registered entity to be responsible for providing estimations of unregistered load. CEHE, as a TO, does not have visibility into an unregistered entity’s systems to provide an estimate of the data at any level of accuracy.	

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, 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

Imperial Irrigation District agrees with the comments provided by the Western Power Pool.

Likes 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	

Response

Please see the DT's response to WPP.

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	No

Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The Transmission Owner (TO) is not always the most suitable entity to collect and provide data for Distributed Energy Resources (DER), particularly in instances where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. If unregistered DER data is critical to the reliability of the BPS, then unregistered DPs that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this	

information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	No
Document Name	
Comment	
The Transmission Owner (TO) is not always the most appropriate entity to collect and provide data for Distributed Energy Resources (DER) in cases where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have been involved in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. As a result, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. For example, while Seattle City Light functions as both a TO and a distribution load-serving entity, it still may not have access to detailed inverter information for DERs that are already installed. In such cases, significant assumptions and estimations would be required to model these resources accurately.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	

Answer	No
Document Name	
Comment	
No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. As such, the proposed MOD-032 modifications allow the PC to obtain DER data as suggested. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
AES Indiana supports comments provided by EEI.	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to EEI.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
The DER's at the connection point should handle the data collection and reporting responsibility	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
AZPS supports the following comments provided by EEI on behalf of its members:	

EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	No
Document Name	
Comment	
No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct	

entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
No, we do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood

through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The Transmission Owner (TO) is not always the most suitable entity to collect and provide data for Distributed Energy Resources (DER), particularly in instances where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have participated in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. Consequently, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. The Transmission Owner is not involved in the connection process for DER, and therefore does not have the data necessary for DER modelling. If there are reliability impact to the BPS due to DER connected where there are no DP, it is suggested that the registration criteria for DP be updated to ensure that all applicable entities that could have BPS impact are registed with NERC. This could be done as an initiative similar to what was done for IBR registration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Richard Vendetti - NextEra Energy - 5	
Answer	No

Document Name	
Comment	
Nextera supports comments provided by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The redlines do not delineate that the TO is the responsible entity to accomplish this effort. Recommend TOP be the responsible party.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	

Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's comments to this question. Black Hills Corporation agrees that the TO should not be held responsible for collecting data on DERs described above. The TO has no direct responsibility or control over these unregistered DER's and do not have direct knowledge of DER connections on the unregistered DP's systems.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	

Comment	
The TO does not always have visibility into DER systems unless they were directly involved in the interconnection agreements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The revised standard seeks to capture 'unregistered IBR' and 'aggregate DER' steady state and dynamics data for various planning horizons. Unregistered IBR is defined only in this standard. It may be more reasonable for the Planning Coordinator to require various data from 'unregistered IBR's' through existing interconnection requirements rather than to require that all unregistered IBR's provide this data to the PC as a compliance requirement. Alternatively, GO/Gop Category 2 or a new Registration should hold that responsibility.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Daren Brubaker - Seattle City Light - 6	
Answer	No
Document Name	
Comment	
I understand SCL is TO and DP, but I think we still need to comment on this. No, the Transmission Owner (TO) is not always the most appropriate entity to collect and provide data for Distributed Energy Resources (DER) in cases where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have been involved in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. As a result, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. For example, while Seattle City Light functions as both a TO and a distribution load-serving entity, it still may not have access to detailed inverter information for DERs that are already installed. In such cases, significant assumptions and estimations would be required to model these resources accurately.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct	

entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP continues to believe that the most efficient and technically appropriate path for implementing this proposed standard is to align with existing registration and data provision frameworks. Specifically, where Distributed Energy Resources (DERs) interconnect and provide data relevant to MOD-032 Attachment One, the entities possessing that data should be properly registered and held accountable under the NERC Functional Model.

As with existing standards requiring Generator Owners (GOs) or Distribution Providers (DPs) to provide planning and modeling data, those entities who control or aggregate DER fleets and are capable of furnishing the required information should be registered accordingly. While it remains unclear whether existing Functional Entities are universally sufficient, or whether a new DER-specific Functional Entity class may be warranted, the need for clear accountability is critical.

To clarify, AEP does not support requiring every individual rooftop solar customer to register as a Functional Entity. Instead, FERC Order No. 2222 Aggregators of DERs (DER Aggregators) could be envisioned as the appropriate responsible parties. These entities are well-positioned to coordinate with their constituent DERs, consolidate the necessary modeling and planning data, and meet compliance obligations.

In our view, the responsibility for MOD-032 data collection and compliance could rest with the DER aggregator, who in turn must coordinate with the Distribution Provider and Transmission Owner for appropriate data sharing and validation. This structure promotes scalability, efficiency, and consistency across jurisdictions, especially considering that DER participation can span both Federal and State regulatory boundaries.

NERC should consider how this evolving aggregator model intersects with the Functional Model and explore registration or oversight pathways that ensure these entities are held accountable without placing undue burdens on small-scale DER owners.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES adopts EEI's comments for MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI comments which state: EEI does not agree that the TO should be held responsible for collecting or providing data for DERs where there is no associated registered DP between the DER connection point and the TO's system because they have no direct responsibilities or control over these non-registered DPs or their distribution system. Moreover, they do not participate or have direct knowledge of DER interconnections on the unregistered DP's system.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's response to question 1.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to BPA's question 1.	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

The appropriate party would be the entity that worked with the DER to create the interconnection agreement. This would include preliminary modeling and verification of performance. The SDT's question is unclear; if the TO worked to interconnect the DER it would be the correct responsible entity, however if the LSE, GO or DP was responsible for the interconnection of the DER they would be the most responsible entity. The SDT also fails to state the voltage level of the interconnection. If the voltage level is above the 100kV threshold, the TO would be responsible, however below that voltage the LSE or DP would most likely be the appropriate entity. Since LSEs are no longer part of the NERC registry, the SDT should submit a SAR requesting that LSEs are once again required to be responsible entities. This may better align the standards with the responsible entities in practice.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
though it is not clear what accountability the TO has for collecting and providing data for DER. Within Ontario there are no DPs as per the IESO Market Rules. I don't think there is another entity that is in a better position to collect and provide the data	
Likes 0	

Dislikes 0	

Response

Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.

Greg Sorenson - ReliabilityFirst - 10 - RF

Answer	Yes
Document Name	

Comment

Where there is no associated DP, the TO is usually in the best position to collect and provide DER data.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	Yes
Document Name	
Comment	
SPP supports the comments filed by the SRC regarding this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to SRC.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
For this question, ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to IRC SRC.	
Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	Yes
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	

The best long-term solution would be for NERC to expand DP registration criteria (or create DER-only DP registration criteria) such that no DER would be connected to the distribution system without being associated with a registered DP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the flexibility proposed in the current draft language.	
Likes 0	
Dislikes 0	
Response	
Thank you 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	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

While Oncor Electric Delivery Company LLC ("Oncor") agrees with the question as phrased, Oncor would like to note that ideally the DER owner would maintain responsibility for adhering to data-sharing requirements. Oncor recognizes, however, that this may not be a practical solution given the broad applicability of the DER definition proposed in the standard. Oncor would also like to propose an alternative approach for the SDT's consideration – in the event that an unregistered DP is between the DER connection point and the TO's system, instead of placing the data collection responsibility on the TO, there could instead be a mandate for any such DPs to register. This would keep the data sharing requirements with the DP who may be better positioned to provide more accurate data than the TO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood that through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emma Halilovic - Hydro One Networks, Inc. - 1	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
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	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
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; Kris Kirkegaard, 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	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
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	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
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	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
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; John Nierenberg, 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	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EPRI is agnostic as to this question about whom may be the appropriate responsible entity for collecting and providing data and we abstain from answering with "Yes" or "No" to this question.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
No, the Transmission Owner (TO) is not always the most appropriate entity to collect and provide data for Distributed Energy Resources (DER) in cases where there is no registered Distribution Provider (DP) between the DER interconnection point and the TO's system. The TO may not have been involved in the DER interconnection process and may lack visibility into the DER systems, including specific inverter details and settings. As a result, the TO may not have access to accurate DER/IBR modeling parameters unless it was directly involved in the interconnection agreements. For example, while Seattle City Light functions as both a TO and a distribution load-serving entity, it still may not have access to detailed inverter information for DERs that are already installed. In such cases, significant assumptions and estimations would be required to model these resources accurately.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provided, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	

3. Do you agree with the proposed IRO-010-5 and TOP-003-8 modifications to address the FERC Order 901 directives? Please reference the technical rationale and consideration of FERC directives. If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI comments which state:

Consistent with EEI concerns as stated in our response to question 1, we do not agree that enforceable Reliability Standards should be reliant on external documents such as the document titled "ERO Approved Criteria for Acceptable Models" (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. To address our concerns with this issue in both IRO-010-6 and TOP-003-8 we offer the following comments and edits in boldface:

IRO-010-6 Concerns

Requirement R1: The following suggested changes to IRO-010-6, Requirement R1, part 1.5.3 (in boldface) align with our proposed changes to MOD-032 and provide RCs with similar capabilities as provided to PCs in that standard. We believe these changes will satisfy FERC Order 901 directives, place the criteria within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection.

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-

specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to.:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization; Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data. for the following items for dynamic models submitted in accordance with Attachment 1: **1.5.3.1. A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;** **1.5.3.2. Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s) and/or user-written models along with an explanation of the use case(s) for each model type.** **Criteria for any submitted user-written models including, at a minimum, documentation and performance criteria to minimize the risk of non-convergence and other issues. The RC's user-written model criteria must be made available to all other RCs within the Interconnection for review and comment, and approval where the user-written model represents a shared impact.**

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES adopts EEI's comments for IRO-010-5 and TOP-003-8	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	

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; John Nierenberg, 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 does not agree that TOP-003-8 R1.5.3 and R2.5.3 are necessary to "further enhance real-time visibility of Bulk-Power System operations" (FERC Directive p 86). The changes to TOP-003-8 R1.1 and R2.1 adequately address this FERC directive. The proposed new sub-Requirements R1.5.3 and R25.3 are not. related to this directive, as the data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility.

Tacoma Power does not agree with expanding the scope of TOP-003-8 to include model submissions and requesting modeling data. TOP-003 should continue to focus on the data needed for real-time operations (e.g. RTAs and OPAs). The TOP-003 sub-Requirements related to requesting modeling data in R1.5.3 and R2.5.3 should be removed from TOP-003-8. Additionally, TOP-003-8 R2.5.3 is redundant to MOD-032-2 R2.

If a Requirement is needed to ensure the TOP is capable of requesting modeling data, then Tacoma Power recommends modifying MOD-032 and add the TOP as a functional entity in this Standard. If the SDT determines that the scope of TOP-003-8 should be expanded to include modeling data, then Tacoma Power recommends modifying TOP-003-8 R1.5.3 to clarify that the TO is the appropriate responsible entity for collecting and providing modeling data for DERs where there is no associated registered DP (and not the TOP or BA), similar to the approach taken in the MOD-032-2 redline. TOP-003-8 would then need to be modified to include the TO as a functional entity.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The proposed new TOP-003 sub-Requirements R1.5.3 and R2.5.3 do not impose requirements for the TOP or BA to obtain or utilize data not needed for real-time operations (such as Real-Time Assessments and Operational Planning Analyses). Data "deemed necessary" by the TOP or BA is required in accordance with R1 Part 1.1 or R2, Part 2.1. However, to the extent the TOP or BA needs

modeling data, it should be consistent with modeling data provided under MOD-032. Both BAs and TOPs are specifically called out in FERC Order No. 901 as entities that should be receiving IBR data within a uniform framework (p76, p141, p161). Thus, the drafting team contends that the proposed modifications to TOP-003 are necessary and aligned with the FERC 901 directives.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
Chelan PUD does not agree that TOP-003-8 R1.5.3 and R2.5.3 are necessary to "further enhance real-time visibility of Bulk-Power System operations" (FERC Directive p 86). The proposed new sub-Requirements for TOP-003 R1.5.3 and R2.5.3 are not related to this directive, as the data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility. Chelan PUD does not agree with expanding the scope of TOP-003-8 to include model submissions and requesting modeling data. TOP-003 should continue to focus on the data needed for real-time operations (e.g. RTAs and OPAs). CHPD agrees to the recommended changes for IRO-010-5.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed new TOP-003 sub-Requirements R1.5.3 and R2.5.3 do not impose requirements for the TOP or BA to obtain or utilize data not needed for real-time operations (such as Real-Time Assessments and Operational Planning Analyses). Data "deemed necessary" by the TOP or BA is required in accordance with R1.1 or R2.1. However, to the extent the TOP or BA needs modeling data, it should be consistent with modeling data provided under MOD-032. Both BAs and TOPs are specifically called out in FERC Order N0. 901 as entities that should be receiving IBR data within a uniform framework (p76, p141, p161). Thus, the drafting team contends that the proposed modifications to TOP-003 are necessary and aligned with the FERC 901 directives.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	

Comment
Proposed modifications to IRO-010-5 and TOP-003-8 both reference the ERO Criteria for Acceptable Models. See our comments for Question 1.

Likes 0	
Dislikes 0	

Response
Please see the DT's response to your Q1.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment
Requirement R1 Part 1.1 of the draft IRO-010-6 and TOP-003-8 now specifies IBR-specific "data and parameters". It is not clear if the drafting team identified a material difference that would mandate IBR-specific data **and** IBR-specific parameters as necessary condition for compliance. The addition in Part 1.5.3 clarifies that the data specification must include methods to provide data that include requirements for model submissions in accordance with the Criteria for Acceptable Models. BC Hydro suggests that using "IBR-specific data" in Part 1.1. in conjunction with the additional Part 1.5.3 is sufficient; otherwise, we request that the drafting team provides additional clarity on what would constitute adequate and sufficient evidence to demonstrate compliance for IBR data and IBR parameters. Requirement R1 Part 1.5.3 of the draft IRO-010-6 and TOP-003-8 (as well as R2 Part 2.5.3 of TOP-003-8) mandates that the data spec must include methods to provide data that include "requirements for model submissions in accordance with the Criteria for Acceptable Models". BC Hydro's understanding (supported by the Technical Rationale) is that the intent here is to mandate that data models must be in accordance with the Criteria for Acceptable Models, rather than their submission, which must be in accordance with the method specified pursuant to Part 1.5. Revised wording for clarity is provided below:

1.5.3 Requirements that data models are in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. Yes, the team intended for the language to read IBR-specific data and IBR specific parameters. 2. Please see the updated IRO and TOP standard language. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase “Bulk-Power System” from this description to remove any potential for ambiguity in application.	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI’s comments to this question for similar reasoning used for question 1. We agree with their suggested changes to IRO-010-5 and TOP-003-8. Black Hills Corporation would support combining the requirements from IRO-010-5 into TOP-003-8 and retiring IRO-010-5.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation abstains from this question as it does not have IBR/DER resources.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	

Comment
Nextera supports comments provided by EEI

Likes 0	
Dislikes 0	

Response
Please see the DT's response to EEI.

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment
(1) The added sub-requirement 1.5.3 should be removed from this standard as it pertains to data and information collection, not model submissions. The data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility. This requirement is already addressed in MOD-032-2 R1 (sub-requirement 1.2). (2) The statement "Inverter-based Resource (IBR)-specific data and parameters" added to section 1.1 should be removed or more inclusive of including all other facilities, of which IBR's are a subset. It is suggested that the statement be augmented to the following, "including Generator, FACTS, aggregate DER and Inverter-based Resource (IBR)-specific data and parameters".

Likes 0	
Dislikes 0	

Response
Thank you for your comments.

The DT feels the TOP-003 and IRO-010 Reliability Standards can stand on its own for any data to be requested by entities; however, the DT felt it was appropriate to add the new sub-requirement to ensure entities are aware that this type of data can be requested by entities who need to be compliant with MOD-032. Requirement R1 of MOD-032 identifies the procedures, and the data needed. The proposed new TOP-003 sub-Requirements Requirement R1, Part 1.5.3 and Requirement R2, Part R2.5.3 do not impose requirements for the TOP or BA to obtain or utilize data not needed for real-time operations (such as Real-Time Assessments and Operational Planning Analyses). Data "deemed necessary" by the TOP or BA is required in accordance with R1.1 or R2.1. However, to the extent the TOP or BA needs modeling data, it should be consistent with modeling data provided under MOD-032. Both BAs and TOPs are specifically called out in FERC Order N0. 901 as entities that should be receiving IBR data within a uniform framework (p76, p141, p161). Thus, the drafting team contends that the proposed modifications to TOP-003 are necessary and aligned with the FERC 901 directives.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI and MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI and MRO NSRF.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	

AES Indiana supports comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	No
Document Name	
Comment	
Support Tacoma Power's comment	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Tacoma Power.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The added sub-requirement 1.5.3 should be removed from this standard as it pertains to data and information collection, not model submissions. The data collected for the Criteria for Acceptable Models is for modeling and not for real-time visibility This requirement is already addressed in MOD-032-2 R1 (sub-requirement 1.2).	

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Thank you for your comment. The proposed new TOP-003 sub-Requirements R1.5.3 and R2.5.3 do not impose requirements for the TOP or BA to obtain or utilize data not needed for real-time operations (such as Real-Time Assessments and Operational Planning Analyses). Data "deemed necessary" by the TOP or BA is required in accordance with R1.1 or R2.1. However, to the extent the TOP or BA needs modeling data, it should be consistent with modeling data provided under MOD-032. Both BAs and TOPs are specifically called out in FERC Order N0. 901 as entities that should be receiving IBR data within a uniform framework (p76, p141, p161). Thus, the drafting team contends that the proposed modifications to TOP-003 are necessary and aligned with the FERC 901 directives.

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, 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

For TOP-003-8: Imperial Irrigation District agrees with the comments provided by Tacoma Power.

Likes 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	

Response

Please see the DT's response to Tacoma Power.

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment	
CEHE supports EEI's comments.	
Likes 0	
Dislikes 0	

Response	
Please see the DT's response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment
Consistent with EEI concerns as stated in our response to question 1, we do not agree that enforceable Reliability Standards should be reliant on external documents such as the document titled "ERO Approved Criteria for Acceptable Models" (FERC Order 901, P 125) for the establishment of enforceable and auditable compliance requirements. To address our concerns with this issue in both IRO-010-6 and TOP-003-8 we offer the following comments and edits in boldface:
IRO-010-6 Concerns
Requirement R1: The following suggested changes to IRO-010-6, Requirement R1, part 1.5.3 (in boldface) align with our proposed changes to MOD-032 and provide RCs with similar capabilities as provided to PCs in that standard. We believe these changes will satisfy FERC Order 901 directives, place the criteria within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection.
R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

{**1.3.2.2.** historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to.:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data. for the following items for dynamic models submitted in accordance with Attachment 1:

1.5.3.1. A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.5.3.2. Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s) and/or user-written models along with an explanation of the use case(s) for each model type.

1.5.3.3. Criteria for any submitted user-written models including, at a minimum, documentation and performance criteria to minimize the risk of non-convergence and other issues. The RC's user-written model criteria must be made available to all other RCs within the Interconnection for review and comment, and approval where the user-written model represents a shared impact.

1.5.4 Provisions to update or correct data and information, as applicable or necessary.;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

TOP-003-8 Concerns

Requirement R1: The following suggested changes to TOP-003-8, Requirement R1, part 1.5.3 (in boldface) align with our proposed changes to MOD-032 and provide RCs with similar capabilities as provided to PCs in that standard. We believe these changes will satisfy FERC Order 901 directives, place the criteria within the requirements of the Reliability Standard, allow the use of user-defined models when needed and ensure sharing and coordination across the interconnection.

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1 A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2 Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3 Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1 capability and availability;

1.3.1.2 fuel supply and inventory concerns;

1.3.1.3 fuel switching capability; and

1.3.1.4 environmental constraints

1.3.2 Generating unit(s) minimum:

1**.3.2.1** design temperature; or

1.3.2.2 historical operating temperature; or

1.3.2.3 current cold weather performance temperature determined by an engineering analysis.

1.4 Identification of a mutually agreeable process for resolving conflicts.

1.5 Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following:

1.5.1 Specified deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3 Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data for the following items for dynamic models submitted in accordance with Attachment 1:

1.5.3.1 A list of unacceptable models1 which are not to be submitted unless there is no alternative model available;

1.5.3.2 Required submission of standard library model types provided with the software(s) utilized to create the interconnection-wide case(s) and/or user-written models along with an explanation of the use case(s) for each model type.

1.5.3.3 Criteria for any submitted user-written models including, at a minimum, documentation, and performance criteria to minimize the risk of non-convergence and other issues.

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

Footnote 1: For example, the Unacceptable Model List included in NERC's Dynamic Modeling Recommendations and/or other lists maintained by the entities responsible for creating interconnection-wide base cases.

Requirement 2: EEI is of the opinion that Requirement R2, subpart 2.54 was added in error and should be removed. It is our understanding that the BA is not responsible for Steady State, Dynamic or Short Circuit modeling and therefore has not useful utility.

Likes 0	
Dislikes 0	

Response
Thank you for your comment.

Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF

Answer	No
Document Name	

Comment
SIGE supports EEI comments

Likes 0	
Dislikes 0	

Response	
Please see the DT’s response to EEI.	
Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	

Answer	No
Document Name	
Comment	

NIPSCO also supports MISO's comments referenced below:

"NERC Standards often default to the lowest common denominator in terms of data quality, which can compromise model accuracy. To ensure more reliable and representative system models, NERC should strengthen data submission requirements. Specifically, MOD-032 should explicitly state that submitted data must accurately reflect how equipment is configured and operates in the field."

And,

"Consistent with the response to Q1 above providing a superior alternative to the separate ERO criteria document, the language in IRO-010-6 Requirement R1, Part 1.5.3; TOP-003-8 Requirement R1, Part 1.5.3; and TOP-003-8 Requirement R2, Part 2.5.3 should be changed to read as follows:

Requirements for model submissions consistent with the model submitted for planning purposes in accordance with MOD-032;

Referencing MOD-032 instead of a separate ERO criteria document satisfies FERC's directives in Order No. 901 by ensuring consistency between operations models and planning models, while also leveraging model quality and accuracy requirements associated with MOD-032 submissions."

Likes 0	
Dislikes 0	

Response

Please see the DT's response for MISO.

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; Kris Kirkegaard, 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 sub-Requirements R1.5.3 and R2.5.3 in TOP-003-8 are not necessary to enhance "***real-time visibility***" [emphasis added] of Bulk Power System operations as outlined in the FERC Directive (p. 86). We feel that the changes made to Requirements R1.1 and R2.1 adequately address this FERC directive.

The proposed new sub-Requirements R1.5.3 and R2.5.3 appear to focus on data collected for modeling purposes, specifically in relation to the "ERO Approved Criteria for Acceptable Models" document, rather than contributing to real-time visibility. Additionally, sub-Requirement R2.5.3 seems to duplicate Requirement R2 of MOD-032-2.

We suggest that the scope of TOP-003-8 remains focused specifically on the data required for real-time operations, such as Real-Time Assessments and Operational Planning Analyses. To that end, we recommend the removal of the sub-Requirements R1.5.3 and R2.5.3, as they involve requests for modeling data which do not align with the purpose of TOP-003-8.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Thank you for your comment. The proposed new TOP-003 sub-Requirements R1.5.3 and R2.5.3 do not impose requirements for the TOP or BA to obtain or utilize data not needed for real-time operations (such as Real-Time Assessments and Operational Planning Analyses). Data "deemed necessary" by the TOP or BA is required in accordance with R1.1 or R2.1. However, to the extent the TOP or BA needs modeling data, it should be consistent with modeling data provided under MOD-032. Both BAs and TOPs are specifically called out in FERC Order N0. 901 as entities that should be receiving IBR data within a uniform framework (p76, p141, p161). Thus, the drafting team contends that the proposed modifications to TOP-003 are necessary and aligned with the FERC 901 directives.

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment	
The added sub-requirement 1.5.3 should be removed from this standard as it pertains to data and information collection, not model submissions. This requirement is already addressed in MOD-032-2 R1 (sub-requirement 1.2).	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comment. Data will need to be collected to allow for an accurate model to be completed in submitted through MOD-032. In addition, Transmission Operators are not an applicable entity of MOD-032, and per the FERC Order 901, this allows those entities to gather data needed in order to accurately complete its model.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

The NAGF supports the comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to EEI.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Invenergy does not agree with the revisions to IRO-010-5 and TOP-003-8. Specifically, the standards are no longer self-contained and require entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that R1.5.3 of IRO-010-5 and R1.5.3 and R2.5.3 of TOP-003-8 be removed entirely or revised to state, "Requirements for model submissions consistent with MOD-032-2."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the updated IRO and TOP Reliability Standards. The DT removed the MOD-032 phrase.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy does not agree with the revisions to IRO-010-5 and TOP-003-8. Specifically, the standards are no longer self-contained and require entities to reference external information, developed and updated outside of the standards balloting process and not contained within the standard, to determine the required level of performance. Invenergy recommends that R1.5.3 of IRO-010-5 and R1.5.3 and R2.5.3 of TOP-003-8 be removed entirely or revised to state, "Requirements for model submissions consistent with MOD-032-2."	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the updates to the respective standards of this project.	
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 the opinion of ACES that NERC registered entities should not be subjected to potential violations of multiple NERC Reliability Standards Requirements for a single action. In other words, we contend that by including requirements for model submissions in both MOD-032-2 and in a documented data specification(s), responsible entities will now be subject to a form of double jeopardy (i.e., claim preclusion). ACES recommends only requiring model submissions under MOD-032-2 and subsequently striking the following newly proposed requirement parts: IRO-010-6 Requirement R1 Part 1.5.3, TOP-003-8 Requirement R1 Part 1.5.3, and TOP-003-8 Requirement R2 Part 2.5.3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The team does not agree that there is double jeopardy at play. Entities will request data needed from the respective IRO-010 or TOP-003 standard to complete the model required from MOD-032. Requirement R1 in MOD-032 is where the PC and its TP will draft out the procedures needed to complete the requirements following R1.	
Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	

California ISO abstains from the response to this question.

Consistent with the response to Q1 above providing a superior alternative to the separate ERO criteria document, the language in IRO-010-6 Requirement R1, Part 1.5.3; TOP-003-8 Requirement R1, Part 1.5.3; and TOP-003-8 Requirement R2, Part 2.5.3 should be changed to read as follows:

"Requirements for model submissions consistent with the model submitted for planning purposes in accordance with MOD-032;"

Referencing MOD-032 instead of a separate ERO criteria document satisfies FERC's directives in Order No. 901 by ensuring consistency between operations models and planning models, while also leveraging model quality and accuracy requirements associated with MOD-032 submissions.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Please see the DT's response to your question 1.

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

Please see the DT's response to EEI.

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
The TOP-003 data request language for IBR models is concerning. Other models are not asked for so the specificity about IBRs is unusual.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. IBR is addressing FERC Order 901, where it directs NERC to include IBR-DER.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
For this question, ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to IRC/SRC.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	

Comment	
SPP supports the comments filed by the SRC regarding this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to SRC.	
Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	
TXNM Energy feels that RTO (real-time operations) and OPA (operating planning analysis) communication and modelling are two separate actions, and this muddles the two	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed new TOP-003 sub-Requirements R1.5.3 and R2.5.3 do not impose requirements for the TOP or BA to obtain or utilize data not needed for real-time operations (such as Real-Time Assessments and Operational Planning Analyses). Data "deemed necessary" by the TOP or BA is required in accordance with R1.1 or R2.1. However, to the extent the TOP or BA needs modeling data, it should be consistent with modeling data provided under MOD-032. Both BAs and TOPs are specifically called out in FERC Order N0. 901 as entities that should be receiving IBR data within a uniform framework (p76, p141, p161). Thus, the drafting team contends that the proposed modifications to TOP-003 are necessary and aligned with the FERC 901 directives.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
BPA supports the language as long as its directed towards the appropriate registered entity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the following comments submitted by EEI on behalf of its members:	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	

Comment	
Portland General Electric (PGE) supports the Western Power Pool’s comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to WPP.	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI and MRO NSRF.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

ATC does not have any comments on these proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 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	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 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	

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
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	
Matt Lewis - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
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	

Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
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 supports most of the standard revisions to IRO-010 and TOP-003. However, significant changes to NERC's external document "ERO Approved Criteria for Acceptable Models document" since the last IRO-010 and TOP-003 revisions, specifically the inclusion of criteria modifications that could impact a Registered Entities compliance, highlight our significant concern with the proposed IRO-010 and TOP-003 revisions.

There are simple changes that NERC can make IRO-010 and TOP-003 revisions a success. This includes:

1. Moving any criteria in the "ERO Approved Criteria for Acceptable Models document" within the standard, and converting the external model reference to a "ERO Approved Acceptable Models list" consistent with FERC 901 requirements. Additional comments are included in question 6.
2. TOP-003 R2 should not apply to BAs as they do not use steady state, short circuit, and dynamic modeling data as part of their responsibilities.
3. The following requirement needs to be explicitly added to the standard:
    - "Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the ERO; unless it shall otherwise reduce the viability of the [RC, BA, TOP] ability to perform their analysis functions in a timely manner."
    - In the ERO document, Item #4 must be removed. It is unnecessary, not applicable to operational models, and impractical.
    - In the ERO document, Item #5 must include clarifications similar to previous versions. For example:
        - *"Models shall not reduce the viability of a Registered Entity's ability to perform their OPAs and RTAs in a timely manner. This may require uses of models listed on the Unacceptable Model List provided the model is accompanied by sufficient documentation to explain the parameters, states, and usability of the model to simulate small signal and large disturbance behavior for the scope of responsibility of the NERC Registered Entity."*

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Please see the updated standards modifications. The proposed new TOP-003 sub-Requirements R1 Part 1.5.3 and R2 Part 2.5.3 do not impose requirements for the TOP or BA to obtain or utilize data not needed for real-time operations (such as Real-Time Assessments and Operational Planning Analyses). Data “deemed necessary” by the TOP or BA is required in accordance with Requirement R1, Part 1.1 or R2, Part 2.1. However, to the extent the TOP or BA needs modeling data, it should be consistent with modeling data provided under MOD-032. Both BAs and TOPs are specifically called out in FERC Order No. 901 as entities that should be receiving IBR data within a uniform framework (p76, p141, p161). Thus, the drafting team contends that the proposed modifications to TOP-003 are necessary and aligned with the FERC 901 directives. Please see the updated ERO Unacceptable Models List Document.	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EPRI agrees with the intent of the proposed IRO-010-5 and TOP-003-8 modifications but abstains from answering with "Yes" or "No" to this question. EPRI research informs the potential need and feasibility of changes to IRO-010-5 and TOP-003-8, see for example the references listed in response to Q1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and additional information.	

4. Do you agree with the proposed DER definition? Please refer to the technical rationale, which provides rationale behind the drafting team's intent and previous definitions proposed. If you do not support the definition as proposed, please explain the changes that, if made, would result in your support.	
Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	
TXNM agrees with MRO's statement on definition.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
SPP supports the comments filed by the SRC regarding this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to SRC.	

Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	

ERCOT abstains from the response to this question.

The proposed definition does not explicitly include demand reduction in the DER definition. For a complete definition, this should be more clearly indicated whether it is or is not included.

Distributed Energy Resources (DER): Generators and energy storage technologies connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an end-use customer that is supplied from a distribution system.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Demand reduction is not considered DER unless that demand reduction is due to a generator or storage technology. As explained in the Technical Rationale:

Additionally, the DT intention was to ensure that the scope included facilities “connected behind the meter of an end use customer” that may export Real Power to the power system **or offset Real Power** load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load.

Colten Mitchell - Indiana Municipal Power Agency - 4	
Answer	No
Document Name	

Comment
No. Both proposed standards (MOD-032-2; MOD-033-3) rely on the proposed DER definition to describe the IBR-DERs that Order 901 directs these standards to address, in aggregate, for purposes of data reporting and modeling. *See, e.g.*, proposed MOD-032-2, R2.2.1 & n.1; proposed MOD-033-3, R1.1.2. A key problem with the proposed use of the DER definition is that it is inconsistent with Order 901's express intent and directives, and therefore will undermine FERC's objectives, described above, to accurately represent IBRs, which is needed because such generation responds differently to system disturbances than synchronous generation. Although Order 901 expressly directs the development of standards requiring the provision of data and modeling of aggregate IBR-DERs, the proposed draft standards use a generalized DER definition, which includes both IBRs and non-IBR generation. *See, e.g.*, Order 901, PP 7, 53. *See also* MOD-032-2 Technical Rationale Figure 2 (at 5). While the MOD-032-2 Technical Rationale, at 7, found it practical to have a consistent estimation framework for all DERs regardless of technology, the proposed DER definition fails to isolate IBR-DERs so that their impacts can be analyzed and appropriately accounted for in modeling, operations, and planning. The addition of Item 9.c under the "steady-state" column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, but the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards invites confusion that could also carry over to other standards that are intended to account for the particular characteristics of IBRs. For example, Item 10 under "dynamics" of MOD-032-2 Attachment 1 fails to make the distinction captured in Item 9.c. *Compare* Order 901, PP 37-39, 50-56. MOD-033-3 footnote 1 likewise refers to the DER definition without focusing on those DERs that are IBRs. Thus, the proposed homogenized DER definition may impede the ability of these standards, and other IBR-related standards, to achieve Order 901's reliability objectives. Steps should be taken to more clearly define IBR-DERs or otherwise further mitigate the potential adverse impacts of use of the proposed DER definition. Context for and a summary of all concerns with proposed MOD-032-2 are provided in Question 1; further concerns with regard to the unregistered IBR definition are provided in Question 7.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response
Thank you for your comments. The DT, through the NERC standards development processes, found that the term DER aligns with the definition of IBR-DER in FERC Order 901 for assets that are IBRs connected through a distribution system. As such devices, both IBR and

synchronous (as in the Figure in the TR), connect through a distribution system, the local distribution regulator requires similar safety and performance standards, e.g., IEEE 1547 applies to both IBR and synchronous devices connecting through the distribution system. Thus, the team felt it appropriate to align the definition with the SPIDERWG working definition of DER which was developed with the concept of applicability within NERC reliability standards. When IBR-DER is the sole focus, that use of both terms can be used to clarify the subset of DER that is IBR.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC recommends adding the following in **bold**, and removing the following in *italics*: Distributed Energy Resources (DER): ITC proposes the following change to the DER definition to add more clarity regarding the IBR connected to a distribution system "Generators, **and IBR** *energy storage technologies* connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an end-use customer that is supplied from a distribution system".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Some IBR's are generators, and some are storage devices. The DT wants to ensure that all generators and all storage devices are included within DER that are applicable. It is also not the case that all storage devices are IBR. Based on this reasoning, the DT believes that "generators and energy storage technologies" are the appropriate terms to be included in the DER definition.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	

Comment	
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	

Response
Please see the DT's response to MRO NSRF.

Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	

Comment
ATC is of the opinion that the DER definition should be modified as suggested below: **Distributed Energy Resources (DER):** Generators and energy storage technologies connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System**,** including those connected behind the meter of an end-use customer that is supplied from a distribution system**, based on the MVA threshold defined by the Planning Coordinator.**

Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	

Response
Thank you for your comment. The DT believes that a definition should not define a threshold but should simply explain what the term means. In addition, based on outreach with industry, the threshold is not the same answer across the board for various entities. If a threshold ever needs to be defined, it should be completed through the Facilities section of a standard or through requirement language. The DT added footnote 7 in the footnote table in Attachment 1 that allows the TP/PC to establish modeling thresholds through R1.

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	
Comment	
Distributed Energy Resources (DER): propose the following change to DER definition add more clarity regarding the IBR connected to a distribution system "Generators, and IBR connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an enduse customer that is supplied from a distribution system".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Some IBR's are generators, and some are storage devices. The DT wants to ensure that all generators and all storage devices are included within DER that are applicable. It is also not the case that all storage devices are IBR. Based on this reasoning, the DT believes that "A generator or energy storage technology" are the appropriate terms to be included in the DER definition.	
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; Kris Kirkegaard, 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 provided by Tacoma Power on the DER definition.	
Likes 0	
Dislikes 0	

Response	
Please see the DT's response to Tacoma Power.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

No. Both proposed standards (MOD-032-2; MOD-033-3) rely on the proposed DER definition to describe the IBR-DERs that Order 901 directs these standards to address, in aggregate, for purposes of data reporting and modeling. *See, e.g.*, proposed MOD-032-2, R2.2.1 & n.1; proposed MOD-033-3, R1.1.2. A key problem with the proposed use of the DER definition is that it is inconsistent with Order 901's express intent and directives, and therefore will undermine FERC's objectives, described above, to accurately represent IBRs, which is needed because such generation responds differently to system disturbances than synchronous generation.

Although Order 901 expressly directs the development of standards requiring the provision of data and modeling of aggregate IBR-DERs, the proposed draft standards use a generalized DER definition, which includes both IBRs and non-IBR generation. *See, e.g.*, Order 901, PP 7, 53. *See also* MOD-032-2 Technical Rationale Figure 2 (at 5). While the MOD-032-2 Technical Rationale, at 7, found it practical to have a consistent estimation framework for all DERs regardless of technology, the proposed DER definition fails to isolate IBR-DERs so that their impacts can be analyzed and appropriately accounted for in modeling, operations, and planning. The addition of Item 9.c under the "steady-state" column in MOD-032-2 Attachment 1 may somewhat mitigate the adverse impact of this combined IBR/non-IBR DER definition, but the use of the DER definition without express restrictions to IBR-DERs elsewhere in the proposed draft standards invites confusion that could also carry over to other standards that are intended to account for the particular characteristics of IBRs. For example, Item 10 under "dynamics" of MOD-032-2 Attachment 1 fails to make the distinction captured in Item 9.c. *Compare* Order 901, PP 37-39, 50-56. MOD-033-3 footnote 1 likewise refers to the DER definition without focusing on those DERs that are IBRs.

Thus, the proposed homogenized DER definition may impede the ability of these standards, and other IBR-related standards, to achieve Order 901's reliability objectives. Steps should be taken to more clearly define IBR-DERs or otherwise further mitigate the potential adverse impacts of use of the proposed DER definition.

Context for and a summary of all concerns with proposed MOD-032-2 are provided in Question 1; further concerns with regard to the unregistered IBR definition are provided in Question 7.	
Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Thank you for your comments. The DT, through the NERC standards development processes, found that the term DER aligns with the definition of IBR-DER in FERC Order 901 for assets that are IBRs connected through a distribution system. As such devices, both IBR and synchronous (as in the Figure in the TR), connect through a distribution system and the local distribution regulator requires similar safety and performance standards, e.g., IEEE 1547 applies to both IBR and synchronous devices connecting through the distribution system. Thus, the team felt it appropriate to align the definition with the SPIDERWG working definition of DER which was developed with the concept of applicability within NERC reliability standards. In addition to FERC Order 901, Project 2022-02 has a separate SAR to address DER specifically. The team felt this was an appropriate time to develop a DER definition while IBR-DER is being captured per FERC Order 901.

Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

Oncor Electric Delivery Company LLC (“Oncor”) considers the “Distributed Energy Resource” (“DER”) definition used in the Technical Rationale for Reliability Standard MOD-032-2 too vague because it does not contain a voltage class threshold for an energy resource to be considered a DER.

Oncor’s view of DER is consistent with ERCOT’s definition of DER, which is: “An electrical generating facility consisting of one or more on-site distributed generation units connected at a voltage less than or equal to 60 kilovolts (kV), which may be connected in parallel operation to the utility system.” This definition can be found here: https://www.ercot.com/files/docs/2017/03/24/DER_OnePager_FINAL.pdf

From Oncor’s experience, the total capacity of the installation’s on-site distributed generation units, a type of distributed energy resource, may exceed ten megawatts (MW).

Is there any MW size threshold for Generator and energy storage technologies to be taken into account when the end-use customer is served at transmission voltage? Oncor would prefer a MW size threshold be specified in the definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT believes that a definition should not define a threshold, but should simply explain what the term means. In addition, based on outreach with industry, the threshold is not the same answer across the board for various entities. The DT added footnote 7 in the footnote table in Attachment 1 that allows the TP/PC to establish modeling thresholds through R1, should a threshold be needed.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
Distributed Energy Resources (DER): MRO NSRF propose the following change to DER definition add more clarity regarding the IBR connected to a distribution system “Generators, and IBR energy connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an enduse customer that is supplied from a distribution system”.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	
Response	
Thank you for your comment. Some IBR’s are generators, and some are storage devices. The DT wants to ensure that all generators and all storage devices are included within DER that are applicable. It is also not the case that all storage devices are IBR. Based on this reasoning, the DT believes that “A generator or energy storage technology” are the appropriate terms to be included in the DER definition.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	

Answer	No
Document Name	
Comment	
AES Indiana supports comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	

MH proposes the following change to DER definition add more clarity regarding the IBR connected to a distribution system "Generators, and IBR connected to a distribution system that are capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including those connected behind the meter of an enduse customer that is supplied from a distribution system".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Some IBR's are generators, and some are storage devices. The DT wants to ensure that all generators and all storage devices are included within DER that are applicable. It is also not the case that all storage devices are IBR. Based on this reasoning, the DT believes that "A generator or energy storage technology" are the appropriate terms to be included in the DER definition.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
DER should not be defined specifically inside of a NERC standard. This needs to be accomplished in the Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed DER definition is being completed through project 2022-02 and once approved, will be moved to the NERC glossary of terms. Please note the paragraph above the proposed term in MOD-032 that states: "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."	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The definition of DER does not include any size requirements, such as voltage or MVA, that specifies when an individual DER or aggregate DER falls under the purview of the standard. TVA recommends adding size requirements to the definition or in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT believes that a definition should not define a threshold but should simply explain what the term means. In addition, based on outreach with industry, the threshold is not the same answer across the board for various entities. If a threshold ever needs to be defined, it should be completed through the Facilities section of a standard or through requirement language. The DT added footnote 7 in the footnote table in Attachment 1 that allows the TP/PC to establish modeling thresholds through R1.	
Julie Hall - Entergy - 6	
Answer	No
Document Name	
Comment	
Entergy is concerned that the clause "*behind the meter of an end-use customer that is supplied from a distribution system*." will require modeling legacy industrial generation behind the meter on distribution where data is not available because of the age of the units, whereas much larger industrial generation behind the meter on the transmission system is not required to be modeled. Entergy has	

concerns that it will not be practical to model all unregistered DER facilities on the Distribution system without some type of DER unit/system MW threshold or aggregated generation MW threshold.	
Likes 1	Scott Brame, N/A, Brame Scott
Dislikes 0	
Response	
Thank you for your comment. The DT believes that a definition should not define a threshold but should simply explain what the term means. In addition, based on outreach with industry, the threshold is not the same answer across the board for various entities. If a threshold ever needs to be defined, it should be completed through the Facilities section of a standard or through requirement language. The DT added footnote 7 in the footnote table in Attachment 1 that allows the TP/PC to establish modeling thresholds through R1.	
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; John Nierenberg, 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 requests clarity from the SDT as to whether the changes to MOD-032-2 apply to small generation plants connected to the transmission system. The proposed DER definition does not include a threshold or criteria for what is considered “distribution”. As a result of not defining this threshold, there is confusion as to what could be considered DER generation. For example, Tacoma Power owns a 4 MW hydro plant connected at 115 kV. Tacoma Power recommends adding clarity in the technical rationale as to whether this revision applies to non-BES synchronous generation connected to the transmission system. A If the intent of the SDT is to include an aggregate of all generating resources in MOD-032-2, then Tacoma Power proposes replacing the word “distribution” with the word “power” in the DER definition. This change would clarify that any non-BES generation must be included within interconnection models, regardless of whether it is connected to transmission or distribution. Alternatively, the SDT could describe in the technical rationale how non-BES synchronous resources connected to the transmission system should be handled under MOD-032.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Replacing “distribution” with “power” in the DER definition would not be appropriate because being connected to a distribution system is the defining characteristic of DER. The Technical Rationale includes a discussion related to the DT decision to use distribution system within the DER definition: “… defining electric facilities as either transmission or distribution is often based on State law or regulations, ISO/RTO tariff, and/or utility tariffs. The DT anticipates there are no conflicts in how applicable entities define distribution and transmission facilities for a given region, even if those definitions vary from region to region.” MOD-032-2 does not specifically address non-BES synchronous generation that is not DER – this was not within the scope of any of the SARs assigned to Project 2022-02 (or FERC 901). Planning Coordinators and Transmission Planners do have the authority to collect data for such facilities if deemed necessary, but there are no specific obligations to do so under MOD-032-2.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES adopts EEI’s comments regarding the proposed DER definition.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes
Document Name	

Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
For this question, ERCOT does not join the comments submitted by the IRC SRC.	
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	
Please see the DT's response to EEI.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
However, the proposed term is not clear enough. Does it intend to call a 15MVa generator connected at 60 kV a DER? Or since it is connected at 60 kV, it is considered a non-BES, unregistered Transmission Line-connected generator and therefore, not covered by the definition? It appears that the SDT has structured the requirement to have two different terms that must be used in tandem to ensure all desired resources are addressed. This could lead to the potential for missing entities in future standards that only use the DER definition without the unregistered IBR Resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT reviewed many definitions and determined that a NERC glossary definition for DER applicable within NERC reliability standards should focus on generation connected through a distribution system in alignment with the NERC SPIDERWG working definition.	
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 EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI has no objections to the proposed definition for DER.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Western Power Pool.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Nextera supports comments provided by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no issues with the Definition.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
The STD has come up with reasonable definition for DERs, however the use of the abbreviation is very limited to The Technical Document and MOD-032, Attachment 1. Rather than adding a definition to the NERC Glossary, perhaps the definition would be better as an addition to the footnotes for Attachment 1 and a definition paragraph in the Technical Document.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT does not feel that a footnote is appropriate for the DER definition currently. Based on conversations with other DTs, this term may be used within other standards, and the DT feels it is important to have one definition for a term being used across other standards so this does not create confusion later.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emma Halilovic - Hydro One Networks, Inc. - 1	
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	
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	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
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	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
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	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
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	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 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	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
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	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EPRI agrees with the intent of the proposed DER definition but abstains from answering with "Yes" or "No" to this question. We note that the SDT considered existing definitions from NERC SPIDERWG & DERTF, IEEE 1547-2018, FERC, CPUC, NYISO, and decided to not align their proposed DER definition with any of these existing definitions. EPRI research informs the potential need and feasibility of changes to IRO-010-5 and TOP-003-8, see for example the references listed in response to Q1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and additional information.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company agrees with the definition as proposed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

5. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-5, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the resources required is only cost effective if the modeling data estimation is useful and backed by actual data. BPA does not support an uninformed modeling data and parameters estimation, as it has no reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Per FERC Order 901 P 103: "We recognize that there may be limitations on the ability of certain transmission owners to provide all data about unregistered IBRs that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System. Likewise, there may be limitations on the ability of certain distribution providers to provide all data about IBR-DERs in the aggregate that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System." Based on this information, it was determined that an estimation is better than nothing, and this is only needed if the functional entity is unable to gather data needed from the respective entity.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

Until response and/or clarification of comments are made by the DT, FirstEnergy cannot determine if these standards can be met in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see modifications made to the respective documents for Project 2022-02 draft 2.	
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; John Nierenberg, 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 agrees that the proposed MOD-032-2 and IRO-010-5 Standards are cost effective. However, Tacoma Power does not agree that the new TOP-003-8 sub-Requirements R1.5.3 and R2.5.3 are cost effective. TOP-003-8 R2.5.3 is redundant to MOD-032-2 R2. The BA collects the relevant modeling data for the Criteria for Acceptable Models guidance via MOD-032-2 R2. It is not cost effective to perform duplicative work. Additionally, the TOP does not have a role in requesting modeling data in the current TOP-003-8. It is not cost effective to require the TOP to collect modeling data under TOP-003-8 R1.5.3. This scope of work should be added to MOD-032-2, if the intent of the SDT is to require the TOP to request modeling submissions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT does not see the modifications to TOP-003 duplicative of MOD-032. The TOP-003 standard allows entities to request the data, and Requirement R2 within the MOD-032 standard is where they input that data into play based on data requirements and reporting procedures developed by its Planning Coordinator.	

Julie Hall - Entergy - 6	
Answer	No
Document Name	
Comment	
Item 25 in the SAR states that a uniform framework among the three standards must be created, and these changes do not accomplish that.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Item 25 in the SAR states: "Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model." Project 2022-02 addresses the unform framework, Project 2020-06 addresses the Generator model verification and validation, and Project 2021-01 addresses the system models. Project 2022-02 lays out the framework and the modifications made to the other project standards point back to MOD-032 where connection is needed.	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	No
Document Name	
Comment	
CHPD agrees that the proposed MOD-032-2 and IRO-010-5 Standards are cost effective. However, CHPD does not agree that the new TOP-003-8 sub-Requirements R1.5.3 and R2.5.3 are cost effective. TOP-003-8 R2.5.3 is redundant to MOD-032-2 R2. The BA collects the relevant modeling data for the Criteria for Acceptable Models guidance via MOD-032-2 R2. It is not cost effective to perform duplicative work.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT does not see the modifications to TOP-003 duplicative of MOD-032. The TOP-003 standard allows entities to request the data, and Requirement R2 within the MOD-032 standard is where they input that data into play based on data requirements and reporting procedures developed by its Planning Coordinator.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA believes that the costs associated with gathering unregistered IBR and aggregate DER data, which will undoubtedly consist of a large percentage of estimated data, do not prove cost-effective as the result may negatively affect model accuracy and provide little, to no, reliability benefit. We also expect there will be unforeseen costs associated with this effort.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Per FERC Order 901 P 103: “We recognize that there may be limitations on the ability of certain transmission owners to provide all data about unregistered IBRs that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System. Likewise, there may be limitations on the ability of certain distribution providers to provide all data about IBR-DERs in the aggregate that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System.” Based on this information, it was determined that an estimation is better than nothing, and this is only needed if the functional entity is unable to gather data needed from the respective entity.	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	No

Document Name	
Comment	
For MOD-32 it is a heavy lift for the DP to provide the additional data requested. Even if an estimate is utilized it takes time to document the methods used for the estimate. Additional time to implement the changes and a gradual approach (i.e prioritizing larger size DER's) could be an approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT understands the concern about this new requirement on DPs. The FERC Order 901 makes it clear the importance of entities understanding what is connected via IBR-DER, aggregated DER, and unregistered DER to the BPS. The requirements have been drafted in ways to make it as easy as possible on DPs, but for reliability purposes, it is important that this data be collected.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation abstains from this question as it does not have IBR/DER resources.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	No

Document Name	
Comment	
Support BPA's comment	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to BPA.	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Since the TO has no ability to force unregistered entities to provide necessary data, delays in modeling are possible, even with a TO's established estimation methodology. The cost will be affected by the time and additional effort needed by the TO to coordinate with unregistered entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This is why FERC Order 901 directed estimations to be completed should data not be provided by the appropriate entity.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	

Comment	
CEHE believes the resources required are only cost effective if the modeling data estimation is useful and backed by actual data. CEHE does not support an uninformed modeling data and parameters estimation, as the TO is not the appropriate registered entity to be responsible for providing estimations of unregistered load.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered DP between the DER connection point. It is understood through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	
Comment	
SIGE does not agree that it addresses the scope in a cost-effective manner. The modifications put a burden on TO's to purchase additional software. There is no easy way to dynamically model; need more defined criteria.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The DT received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point. It was pointed out that this could be the Transmission Owner, Distribution Provider Generator Owner, Balancing Authority, Resource Planner, etc. Based on this information, MOD-032 has been updated to require the Planning Coordinator with its respective Transmission Planner to identify the correct entity to collect and provided data for DER where there is no associated registered DP between he DER connection point. It is understood that through the stakeholder processes in place, entities will be able to work through mutual agreements and any disagreements that need to be resolved.	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
No. As discussed in detail in Questions 1, 4, and 7, the proposed modifications do not effectively address Order 901's directives; as they are not effective, they cannot be cost-effective.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to your questions 1, 4, and 7.	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
The ambiguity potential in Section 2.1 could create a cost burdening requests from Regional Entities. Kimberly Turco on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. PER FERC Order 901, entities have been directed to develop an estimation if data is not provided by the respective entity.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
The ambiguity potential in Section 2.1 could create a cost burdening requests from Regional Entities Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. PER FERC Order 901, entities have been directed to develop an estimation if data is not provided by the respective entity.	
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; Kris Kirkegaard, 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 provided by Tacoma Power.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Tacoma Power.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports comments provided by Bonneville Power.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Bonneville Power.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

The MOD-032 standard continues to expect all other entities to track the needs of the TP and PC rather than having the TP and PC actually ask entities for data they want. This is extremely inefficient for newly registered GOs/GOPs and will likely lead to even larger issues with the registration of entities not connected to the companies that are registered as TPs and PCs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the updated edits to MOD-032.	
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	
Please see our comments regarding questions 1 and 3.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to your questions 1 and 3.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
More clarity is needed with regards to final data responsibility.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's updated edits.	
Scott Thompson - TXNM Energy - 3	
Answer	No
Document Name	
Comment	
TXNM would have to perform a cost analysis and standard impact assessment to know the true cost of these standards as with the increase of responsibility that a TO would take on for these standard modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the updated edits to the standard.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool’s comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to WPP.	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	Yes

Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
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	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
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	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
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	
Steven Sconce - EDF Renewable Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	

Response	
Matt Lewis - Lower Colorado River Authority - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
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	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pirouz Honarmand - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	
Comment	
Support BPA Comment	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to BPA.	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
SCL supports BPA's comments.	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to BPA.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	
Question not applicable for MRO	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
The proposed revisions involve a wide range of modeling variances leading to significant costs and time. Additionally, implementation costs analysis becomes challenging also due to insufficient clarity at this time on Acceptable Models (currently there is a list of Unacceptable Models that may be enforceable). Currently, PCs and TPs have limited ability to collect data from non-registered entities. There does not seem to be a reliability benefit that could be realized before additional mechanisms to collect adequate modeling data on all DERs (including non-registered IBRs and other DER entities), including additional or revised mandatory requirements to provide sufficiently accurate data to TPs and PCs become enforceable	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the updated modifications regarding the ERO Criteria document. FERC Order 901 P87 states: "currently effective Reliability Standards do not ensure that Bulk-Power System planners and operators receive modeling data and parameters regarding unregistered IBRs that, individually or in the aggregate, are capable of adversely affecting the reliable operation of the Bulk-Power System. The Commission also preliminarily found that the currently effective Reliability Standards do not require that Bulk-Power System planners and operators receive modeling data and parameters regarding IBR-DERs that in the aggregate are capable of adversely affecting the reliable operation of the Bulk-Power System. The Commission preliminarily determined that planning coordinators and other entities need modeling data and parameters for both unregistered IBRs and IBR-DERs in the aggregate to assure greater accuracy in modeling."	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
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's primary focus is on electrical system reliability and will not provide a response to this question.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No comment	
Likes 0	

Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC does not have a comment on the cost effectiveness of these modifications.	
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 will not comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Invenergy is unable to comment on the cost effectiveness of the revisions.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Invenergy is unable to comment on the cost effectiveness of the revisions.	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment
EPRI agrees with the intent of the proposed reliability standards but has not analyzed their cost-effectiveness. Hence, we abstain from answering with "Yes" or "No" to this question.

Likes 0	
Dislikes 0	

Response
Thank you for your comment.

6. Do you agree with the proposed ERO Approved Criteria for Acceptable Models document? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	No
Document Name	
Comment	
Regarding the aggregated DER dynamic model, NERC should define a methodology that utilities can follow to derive such an aggregated DER dynamic model before the change is implemented. The methodology must be practical and easy to follow.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the updated information in the technical rationale. It is not the DT's place to tell people how to develop a methodology. However, the DT provided information in the TR to assist those who wish for additional information.	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	No
Document Name	
Comment	
The document does not seem to be written to address both equipment specific and aggregate models. In fact, it seems like the concept of modeling an aggregate IBR-DER or even aggregate dynamic loads may contradict Item #1 under "Usability Requirements"...1) A model	

manual, or other documentation, with a description of all model parameters, variables, and states. The manual or other documentation shall also describe the range of validity of the model and valid use cases or studies for which the model has sufficient fidelity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The ERO Approved Criteria for Acceptable Models content has been altered and moved to a supporting document attached to MOD-032. The information regarding aggregate models and equipment-specific models is not included in the supporting document outlining the process for a model to be added to a list of unacceptable models. Further, the comment claims a contradiction of the criteria for aggregate modeling versus equipment-specific modeling and provides the example of aggregate load component modeling as in conflict with the usability requirements to have a model manual detailing the valid use states of the supplied model. This is not a contradiction to have descriptions of the valid initialization of a dynamic model, whether that model is an aggregate representation of load components, or an equipment-specific model used to represent an individual generation plant.	
Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Regarding the aggregated DER dynamic model, NERC should define a methodology that utilities can follow to derive such an aggregated DER dynamic model before the change is implemented. The methodology must be practical and easy to follow.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the updated information in the technical rationale. It is not the DT's place to tell people how to develop a methodology. However, the DT provided information in the TR to assist those who wish for additional 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	
Please see the DT's response to EEI.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
For this question, ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Please see the Dt's response to the IRC/SRC.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	

Comment	
SPP supports the comments filed by the SRC regarding this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to SRC.	
Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	
Please see the IRC SRC's response to question 1.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to IRC SRC's question 1.	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	

Invenergy recommends that the proposed "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2, rather than separately maintained.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The process for unacceptable models to be added or removed from the ERO Unacceptable Models List Document has been included in the MOD-032 Standard as a Supporting Document. Any updates to this process must be completed through the standards development process. In addition, the ERO will follow this process when adding or removing a model from the list.	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	
Invenergy recommends that the proposed "ERO Approved Criteria for Acceptable Models" be included within MOD-032-2, rather than separately maintained.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The process for unacceptable models to be added or removed from the ERO Unacceptable Models List Document has been included in the MOD-032 Standard as a Supporting Document. Any updates to this process must be completed through the standards development process. In addition, the ERO will follow this process when adding or removing a model from the list.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	No
Document Name	

Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The proposed ERO Approved Criteria for Acceptable Models document suggests that the plant may require two sets of models: operational models and planning models. FERC Order 901 P141 directs NERC to mandate that generator owners of registered IBRs and transmission owners with unregistered IBRs on their system provide Bulk-Power System planners and operators (including planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) with dynamic models that accurately represent the dynamic performance of both registered and unregistered IBRs. This directive appears to aim at ensuring the availability of dynamic models that accurately reflect performance for use in planning and operational studies.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The ERO Approved Criteria for Acceptable Models content has been altered and moved to a supporting document attached to MOD-032. The new revisions have focused on the transient dynamic nature of these models as the comment suggests. The revisions of MOD-032, TOP-003, and IRO-010 did not alter the obligation for the entity to provide data to the TOP or RC data	

specifications nor the TP or PC joint data requirements. In both the operational and planning models, it is expected that the dynamic model be representative of equipment and otherwise represent the dynamic performance of registered IBR, unregistered IBR, and aggregate DERs.	
Brittany Millard - Lincoln Electric System - 5	
Answer	No
Document Name	
Comment	
LES supports MRO's NERC Standards Review Forum's (NSRF) feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
James Merlo - NAGF - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The NAGF supports the comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	

Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC agrees that NERC is responsible for the NERC-Approved Model Library and the associated processes that go along with both maintaining and updating that library. However, we do not agree that Model Criteria should be maintained and modified outside of the Approved Reliability Standards. Model Criteria should not be a moving target. For this reason, we believe that the Model Criteria should be included in the affected Reliability Standards and only changed when those Standards are modified. To address our concerns, we ask that the model criteria be removed from this document and rewrite the document to focus on both the Approved and Unapproved Model Library and associated processes for updating and approving models for industry use. The ERO Approved Criteria for Acceptable Models document should also make clear and define in the document that it applies to generator models, not system models.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. The process for unacceptable models to be added or removed from the ERO Unacceptable Models List Document has been included in the MOD-032 Standard as a Supporting Document. Any updates to this process must be completed through the standards development process. In addition, the ERO will follow this process when adding or removing a model from the list.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment

The ERO document goes beyond an Acceptable Model List and includes criteria that must be included in NERC standards. This is in violation of NERC standard development guidance, FERC 901 requirements, and bypasses the NERC Rules of Procedure for future modifications that can impact entities' compliance with the affected NERC standards.

- In order to comply with the NERC's Acceptance Criteria of a Reliability Standard Item #6 Completeness, "Each Reliability Standard should be complete and self-contained. A standard should not depend on external information to determine the required level of performance." As proposed, the revised standards do not conform to this requirement.
  - The "Criteria for Acceptable Models maintained by the ERO" goes well beyond a library of models as specified by FERC 901, but instead includes compliance criteria for use, interpretation, and adherence of these models.
  - This is of significant concern, as an entity's compliance would become dependent on an external set of criteria not vetted through the NERC standard process.
  - Furthermore, the approval process for changes to the document – which could cause an entity to become non-compliant – would not be subject to NERC standard modifications (essentially bypassing NERC ROP).
- FERC 901 requirements that specify the development of new standards and using the ***standard development process*** to refer to a model library – not an external set of criteria. Therefore, the "Criteria for Acceptable Models maintained by the ERO" should be replaced with a version that is solely focused on a library list of acceptable models.
  - P122 "direct NERC to develop new or modified reliability standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady-state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models"

  - P124 “direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamic studies” [as proposed, it is outside the ***standards development process*** with a separate ERO/RSTC process]
  - P125 “direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models”
- Southern Company acknowledges there is a desire to be agile with the Library – but this agility should not bypass NERC Rules of Procedure
  - If the Acceptable Models truly becomes a library only list, it can include a process by which models can be ***added*** to the list by the ERO and RSTC, but models should not be removed from the list without going through the full industry standard review process as it could significantly modify an entities compliance. Alternatively, a clear implementation schedule not to be less than 2+ years for the removal of any model could be established.
  - If there are critical criteria that must be adhered to from a compliance perspective, these should be incorporated into the specific standards as requirements – not within an external document.
    - For example, it is imperative the RC and TOP retain the flexibility to utilize models needed to meet its OPA and RTA requirements – both for timing, accuracy, and availability. This may require utilizing models that have been reviewed and verified by the entity to perform accurate representation within those operational assessment constraints (e.g., different for remote external areas afar from the scope of responsibility that accurately simulate dynamic response). These criteria and recognition should be embedded in the standard, not an external document.
    - The acceptability criteria for allowance and submission of user-written models should be clear, including coordination for use across interconnection-wide cases.
- The revised NERC Acceptable Models list needs to ensure there are appropriate exceptions, particularly for modeling of neighboring utilities in remote external areas. Specifically:
  - Exceptions must be granted for use of models on the Unacceptable list if the annual NERC MMWG dynamics data library contains these models, since no other source exists for most entities to procure dynamics data for systems beyond their own boundaries.
  - Additionally, for operational models that must meet availability and timing requirements to perform operational-related assessments - constraints that long-term planning analyses do not face – there needs to be accommodations for remote external area modeling outside the scope of the BA, TOP, and RC footprint. For example, the GENCLS model is introduced by the DYNRED program into appropriate system equivalent models which have been verified to accurately represent the dynamic behavior of external generation beyond Tier 1 neighbors of an RC and TOP. This model represents the dynamic behavior of the coherent group as if it were a single generator – substantially reducing computer run-time while maintaining

	all necessary accuracy. Such models must be allowed by the RC and TOP when determined by the RC or TOP to accurately model to simulate small signal and large disturbance behavior for the scope of responsibility of the NERC Registered Entity.
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The process for unacceptable models to be added or removed from the ERO Unacceptable Models List Document has been included in the MOD-032 Standard as a Supporting Document. Any updates to this process must be completed through the standards development process. In addition, the ERO will follow this process when adding or removing a model from the list.	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
Attachment 1 requests data that requires collection of data from OEM's which can be overly burdensome and not possible due to many historical manufacturers no longer in business, thus making the information extremely difficult to obtain. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. It is assumed that the OEM would recommend use of an UDM when they feel no standard library model can adequately reflect their equipment. MOD-032-2 is flexible enough to allow this, but it doesn't mandate the PC/TP to accept UDM and they could require only standard library models – this is usually driven by requirement of the model designee when building Interconnection-wide cases that need to work across multiple software vendors (but there are other options such as requiring the UDMs to be developed for all of the software platforms that are used).	
Kimberly Turco - Constellation - 6	

Answer	No
Document Name	
Comment	
Attachment 1 requests data that requires collection of data from OEM's which can be overly burdensome and not possible due to many historical manufacturers no longer in business, thus making the information extremely difficult to obtain. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. It is assumed that the OEM would recommend use of an UDM when they feel no standard library model can adequately reflect their equipment. MOD-032-2 is flexible enough to allow this, but it doesn't mandate the PC/TP to accept UDM and they could require only standard library models – this is usually driven by requirement of the model designee when building Interconnection-wide cases that need to work across multiple software vendors (but there are other options such as requiring the UDMs to be developed for all of the software platforms that are used).	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI and MRO NSRF.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports and agrees with EEI submitted comments - see EEI comments for Duke Energy's response to this question.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Victoria Crider - Dominion - Dominion Virginia Power - 3, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Please see the DT’s response to EEI.	
Karis Pharr - Southern Indiana Gas and Electric Co. - 6 - RF	
Answer	No
Document Name	
Comment	
SIGE supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No

Document Name	
Comment	

EEI does not support or see a need for the proposed document titled ERO Approved Criteria for Acceptable Models for the reasons provided below. However, we do support the continued use of the NERC document titled "Dynamic Modeling Recommendations", which we believe provides useful guidance to the industry while also containing the Unacceptable Model list. This document would also provide a familiar reference document for the Industry that could be relied upon to provide clarity on unacceptable models and a trusted source of useful recommendations to planners.

1. FERC Order 901 directives clearly "require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models." (see FERC Order 901, P125). While the proposed document does not identify any approved component generic library models to be used when creating interconnection-wide system models.

2. Planning software used by PC and TPs already utilize generic library models that are widely and consistently available through industry planning software, negating the need for NERC to do anything relative to the development of an approved component generic library model list beyond maintaining the existing NERC Unacceptable Model list.

3. We additionally disagree that model criteria should be contained in a standalone document outside of approved Reliability Standards. However, we agree with FERC that model criteria should be uniformly established and shared by PCs, TPs, RCs, TOPs and BAs through the enforceable Requirements contained in the Reliability Standards for each interconnection. (See FERC Order 901, P161)

4. Moreover, the document contains language within the proposed criteria that is far too ambiguous to be enforceable or auditable within a NERC Reliability Standard. (For example: "negligible error(s)", "sufficient fidelity", "robustly initialize", "reasonable initial conditions", or "simulation solution challenges".)

5. We also do not agree that the "Usability Requirements" that cite "simulation crashes" or "solution challenges" as justifications for deeming a model unacceptable. While in some cases, this may be justification for deeming a model unacceptable, such events can be caused by other factors beyond the model and therefore such an arbitrary determination without consideration of other factors may disqualify the best or in some case the only available model.

For these reasons, we ask that the proposed document be abandoned because it provides no useful direction to planners and modelers as originally intended.	
Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to “develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions” (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a “generic model”, and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an “acceptable model library”, but rather an “unacceptable model library”, and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models

added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing. In addition, Representing the impact of UVLS and UFLS on DER (i.e., tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	No
Document Name	
Comment	
The proposed ERO Approved Criteria for Acceptable Models document suggests that the plant may require two sets of models: operational models and planning models. FERC Order 901 P141 directs NERC to mandate that generator owners of registered IBRs and transmission owners with unregistered IBRs on their system provide Bulk-Power System planners and operators (including planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) with dynamic models that accurately represent the dynamic performance of both registered and unregistered IBRs. This directive appears to aim at ensuring the availability of dynamic models that accurately reflect performance for use in planning and operational studies. Could you please clarify whether we are expected to provide both an operational model and a planning model?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the ERO Approved Criteria for Acceptable Models content has been altered and moved to a supporting document attached to MOD-032. The new revisions have focused on the transient dynamic nature of these models as the comment suggests. The revisions of MOD-032, TOP-003, and IRO-010 did not alter the obligation for the entity to provide data to the TOP or RC data	

specifications nor the TP or PC joint data requirements. In both the operational and planning models, it is expected that the dynamic model be representative of equipment and otherwise represent the dynamic performance of registered IBR, unregistered IBR, and aggregate DERs.	
Sing Tay - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
AES Indiana supports comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's feedback.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Nazra Gladu - Manitoba Hydro - 1	

Answer	No
Document Name	
Comment	

The proposed ERO Approved Criteria for Acceptable Models document suggests that the plant may require two sets of models: operational models and planning models. FERC Order 901 P141 directs NERC to mandate that generator owners of registered IBRs and transmission owners with unregistered IBRs on their system provide Bulk-Power System planners and operators (including planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) with dynamic models that accurately represent the dynamic performance of both registered and unregistered IBRs. This directive appears to aim at ensuring the availability of dynamic models that accurately reflect performance for use in planning and operational studies.

Could you please clarify whether we are expected to provide both an operational dynamic model(s) and a planning model(s)? Additionally, we recommend changing the name to “ERO Approved Criteria for Acceptable Dynamic Models,” as the term "Model" could also refer to steady-state and short circuit models.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment, the ERO Approved Criteria for Acceptable Models content has been altered and moved to a supporting document attached to MOD-032. The new revisions have focused on the transient dynamic nature of these models as the comment suggests. The revisions of MOD-032, TOP-003, and IRO-010 did not alter the obligation for the entity to provide data to the TOP or RC data specifications nor the TP or PC joint data requirements. In both the operational and planning models, it is expected that the dynamic model be representative of equipment and otherwise represent the dynamic performance of registered IBR, unregistered IBR, and aggregate DERs.

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	
Comment	

Nextera supports comments provided by EEI	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's conclusion that the "ERO Approved Criteria for Acceptable Models" document may not align with FERC order 901 directives. We agree this document could be responsible for the Model Library and processes needed to submit proposed additions, however the model criteria should be controlled through enforceable requirements within each Reliability Standard.	

Black Hills Corporation also agrees with EEI's comments about the ambiguous language and lack of an Accepted Models list. Also, that the citing of "simulation crashes" or "Solution challenges" may result in a model being deemed unacceptable due to outside factors, even if it is the best or possibly only model available.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
The ERO Criteria for Acceptable Models did not go through any standard process and therefore does not have industry consensus.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves. Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.	

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing. In addition, Representing the impact of UVLS and UFLS on DER (i.e,. tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	
Comment	

R1 reference the ERO maintained Approved Criteria for Acceptable Models. However, this document is not part of the Standard and may pose compliance challenges if updated outside of the Standard Development Process. The process to maintain the list of models (e.g. Unacceptable Model List) relies on NERC determination of the effective date of a change.

For example, if the ERO added a new model to the List of Unacceptable Models in the ERO maintained document without allowing for an adequate implementation timeline, entities may be in noncompliance on the effective date of the revised ERO document.

As drafted the Approved Criteria for Acceptable Models is not clear how and by whom the determination on models that may be acceptable for Planning but not acceptable for Operations is made and documented. It would also be helpful if the Unacceptable Model List includes another column to differentiate between models appropriate for Planning purposes but not appropriate for Operational purposes.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to “develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions” (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a “generic model”, and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an “acceptable model library”, but rather an “unacceptable model library”, and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would

be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing. In addition, Representing the impact of UVLS and UFLS on DER (i.e., tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The ERO Criteria for Acceptable Models does not have industry consensus and was not established through the standards process. TVA does not believe it should be referenced in a compliance standard. In its place, TVA recommends specifications for standard models (where appropriate and available), user-written models (where appropriate and with adequate documentation), and other models (when no alternative is available and requiring justification for use).	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

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advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

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The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.

In addition, Representing the impact of UVLS and UFLS on DER (i.e., tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered

under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
AES adopts EEI's comments for the proposed ERO Approved Criteria for Acceptable Models document.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI comments which state: EEI does not support the document titled ERO Approved Criteria for Acceptable Models because it appears that it does not align with FERC Order 901 directives which "require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models." (see FERC Order 901, P125) While we recognize that the FERC Order 901 may be too restrictive and agree some use of user-defined models is needed, it remains unclear whether NERC has obtained FERC approval to deviate from the Order. Moreover, while we support some use of user-defined models, that usage should be limited and validated across each interconnection with clear enforceable requirements that limit the	

use of user-defined models except when such usage has been coordination between responsible entities across each interconnection. In addition to this core concern, we offer the following additional comments and concerns with this document below:

1. EEI supports the ERO plan to be responsible for the Model Library and the processes needed for responsible entities to submit for approval proposed additions to that library. We do not agree that this document should contain the model criteria itself. While the model library will be a dynamic document, the model criteria should not be dynamic and is most effectively controlled through enforceable requirements within each Reliability Standard.

2. While this document contains a list of Unacceptable Models, it fails to identify any Acceptable Models for use in Interconnection-wide models as required in FERC Order 901.

3.We are also concerned that the document contains language within the proposed criteria that is far to ambiguous to be enforceable or auditable within a NERC Reliability Standard. (For example: “negligible error(s)”, “sufficient fidelity”, “robustly initialize”, “reasonable initial conditions”, or “simulation solution challenges”.)

4.EEI does not agree that the “Usability Requirements” that cite “simulation crashes” or “solution challenges” as justifications for deeming a model unacceptable. While in some cases, this may be justification for deeming a model unacceptable, such events can be caused by other factors beyond the model and therefore such an arbitrary determination without consideration of other factors may disqualify the best or in some case the only available model advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a

supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 to	
Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team received multiple comments expressing concern with the criteria for acceptable models being maintained as a separate document by the ERO. Concerns were raised with both the proposal to maintain the criteria according to a process separate from the standards development process, as well as with the proposed criteria themselves.

Consistent with multiple commenter suggestions, the drafting team incorporated elements for what constitutes an acceptable model to Requirement R1, relating to the requirements and specifications developed by the PC/TP, and has removed reference to a separately maintained ERO Criteria for Acceptable Models document. Entities are not permitted to submit models listed on a separately maintained Unacceptable Models List without justification that supports their use.

In making these changes, the drafting team considered the comments, feedback received on previous drafts, and the FERC Order No. 901 directives. While FERC Order No. 901 directed NERC to “develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions” (P 108), the drafting team determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their interconnection-wide models and subsequently their planning cases.

The drafting team considered that many entities have a different understanding for what is a “generic model”, and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The drafting team further considered that NERC as the ERO does not presently maintain an “acceptable model library”, but rather an “unacceptable model library”, and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion.

Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the

TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

To bookend these criteria for acceptable models, proposed Requirement R1 would also require the PC/TOP to include provisions specifying that any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The drafting team included this provision after considering feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The drafting team believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns.

The drafting team debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the drafting team ultimately decided to include this requirement in Requirement R1, addressing PC/TP data specification requirements, to create one self-contained requirement for data submissions.

The drafting team has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the drafting team has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. This process is moved in substantial part from the draft ERO Approved Criteria for Acceptable Models (chapter 1) included in the last posting to the Attachment 2 to the draft MOD-032 standard. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for Reliability Standards compliance purposes.

As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff is currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the

Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing. In addition, Representing the impact of UVLS and UFLS on DER (i.e., tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) supports the Western Power Pool’s comments.	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to WPP.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 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	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
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	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
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; Kris Kirkegaard, 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	
Joseph Scott - 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	
Carver Powers - Utility Services, Inc. - 4	
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; George Kirschner, 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 2	Imperial Irrigation District, 5, Zaragoza Tino; Imperial Irrigation District, 6, Torres Diana
Dislikes 0	
Response	
Gul Khan - Gul Khan On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Sconce - EDF Renewable Energy - 5	
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	
Erin Doane - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
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	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
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; John Nierenberg, 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	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	

Document Name	
Comment	

EPRI agrees with the intent of the proposed ERO Approved Criteria for Acceptable Models but abstains from answering with "Yes" or "No" to this question.

We share the following observations with the SDT for consideration in future drafts:

–The new terms for the NERC Glossary of Terms proposed by Project 2020-06 for MOD 026/027 etc., i.e., “model validation” and “model verification” are not used in the Criteria for Acceptable Models document.

–In addition to “expected or as-built facilities”, consider adding "as-left" or "as-configured”

–Consider distinguishing between “parameter names” and “parameter values”

–Are standardized tests for “model validation” defined somewhere?

–Consider adding requirements to explicitly document known use cases for which a model shall *not* be used

–Consider changing the term “initial value” to “default value”

–Add a requirement that triggers more thorough model validation whenever models are provided with “default values”

–The term “model adequacy” is used but not defined in the NERC Glossary of Terms as of Feb 26, 2025.

–How would the “explanation of the model’s adequacy” look like? Could it be a "model validation report" for equipment-level models and a "model verification report" for plant-level models, similar to the procedures proposed in IEEE P2800.2 which is currently open for SA initial ballot and public review at https://publicreview.standards.ieee.org/public-review-web/public-app

–Consider clarifying whether "a list of commonly tuned parameters" refers to "parameter values" that are site-specific or the subset of "parameter names" that shall be used to tuned the model to site-specific settings.

–Consider correcting a reference given that Table 1 is now "above".

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The determination of usability ultimately relies on a high degree of engineering judgment. The DT agrees that it is challenging to effectively define usability with precise criteria that can be objectively applied. Please see the proposed modifications made to incorporate the most basic elements of usability (previously described in the ERO criteria document) into the MOD-032. Specific requirements related to model verification and validation are beyond the scope of this project. However, R2.2 was added to require that facility owners provide models that have been verified and validated in accordance with MOD-026 if available.

Scott Thompson - TXNM Energy - 3

Answer	
Document Name	

Comment

The criteria seems vague and usability requirements are not specific, please clarify what would be usable and what would unusable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The determination of usability ultimately relies on a high degree of engineering judgment. The DT agrees that it is challenging to effectively define usability with precise criteria that can be objectively applied. Please see the proposed modifications to incorporate the most basic elements of usability (previously described in the ERO criteria document) into the MOD-032 standard.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
Reclamation abstains from this question as it does not have IBR/DER resources.	
Likes 0	
Dislikes 0	
Response	

7. Provide any additional comments for the drafting team to consider, if desired.	
Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
We appreciate the time and effort put forward by the SDT to resolve FERC's Order 901 directives. It is a difficult job and we feel the SDT has done a good job balancing the interests the industry and FERC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA appreciates the opportunity to respond to this posting. The areas where BPA supports the intent of these revisions is based upon requiring the proper *registered* entity to provide the data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
For the implementation plan for MOD-032-2, AES does not agree with the proposed 12 month time frame after the effective date for MOD-032-2 for requirements R2-R4. Some TPs and PCs may elect to postpone development and publishing of their revised data requirements and reporting procedures until the end of the two-year implementation period for the standard leaving only the 12-month time frame to respond. AES has over 400 unregistered IBRs and DERs in which model information should be provided to the responsible entity. While it could be said that unregistered IBRs and DERs are not required to comply with the standard, it is AES's responsibility to help ensure reliability and provide the requested information in the intended manner. With limited modeling resources, AES requests a longer implementation plan for R2-R4 of at least 24 calendar months following the effective date of the standard.	
Likes 0	

Dislikes 0	

Response

Thank you for your comments. Per Order 901, P 226, "[w]e 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." The DT has provided industry with the best time available to allow the Milestone 4 project implementation time to be implemented by 2030.

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; John Nierenberg, 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 is concerned that the term "unregistered IBR" is not well understood in the industry. Without a formal definition in the Glossary of Terms, it will be difficult for entities to look up the scope of resources that fall under this currently undefined category. Additionally, the term "unregistered IBR" will be used in potentially several Standards, so it would be more efficient to have this term formally defined in the glossary. Defining this term in a footnote of several Standards opens the possibility of the definition being inconsistent between Standards, and would require revising multiple Standards if the definition needs to be updated in the future. In order to ensure efficiency and make it easier to lookup the definition, Tacoma Power recommends using the definition in the MOD-032 footnote to create a NERC glossary definition for Unregistered IBR.

Tacoma Power proposes separate implementation phased dates for MOD-032 compliance for Steady-State versus Dynamics data. The proposed timeline in the implementation plan appears adequate for entering the steady-state data into the interconnection model. The timeline for modeling aggregated DER dynamics data should be extended by an additional 12 months. The modeling tools and base case building process within WECC does not currently have the capability to include multiple different IBR resources within the composite load model. In order to accommodate data for several different IBRs types connected to a single substation transformer, there will need to be extensive collaboration between utilities within WECC. There will also need to be updates by power flow software vendors to implement new composite load models that call for multiple IBR types within a single composite load model. The proposed timeline is vastly too short for

WECC utilities to reach agreement on the updates to the WECC Data Preparation Manual, much less for software developers to be able to provide adequate software implementation once the new requirements are defined.	
Likes 0	
Dislikes 0	

Response

Thank you for your comments. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase “Bulk-Power System” from this description to remove any potential for ambiguity in application.

Per Order 901, P 226, “[w]e 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.” The DT has provided industry with the best time available to allow for the Milestone 4 project implementation time to be implemented by 2030..

Daren Brubaker - Seattle City Light - 6

Answer	
Document Name	

Comment

Seattle City Light has concerns regarding the proposed implementation timeline for modeling dynamic data for Distributed Energy Resources (DER). While the timeline for steady-state DER modeling appears reasonable, dynamic model data for many existing DERs and inverter-based resources (IBRs) is currently unavailable. Additionally, if it is determined that multiple types of IBRs are served by the same substation, utilities like Seattle City Light must ensure that their power system analysis software can accommodate this complexity. Given these challenges, Seattle City Light requests additional time to implement dynamic modeling, particularly for unregistered IBRs.

The term “Unregistered IBR” is not clearly defined in the current revision of the standard. Seattle City Light recommends that a formal definition be added to the NERC Glossary of Terms to promote consistent understanding and interpretation across all applicable entities. Additional Comments – Support TPU Comments re: TOP-003-8

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Per Order 901, P 226, “[w]e 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.” The DT has provided industry with the best time available to allow for the Milestone 4 project implementation time to be implemented by 2030.. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase “Bulk-Power System” from this description to remove any potential for ambiguity in application.

Robert Jones - Seattle City Light - 4	
Answer	
Document Name	

Comment
· Seattle City Light has concerns regarding the proposed implementation timeline for modeling dynamic data for Distributed Energy Resources (DER). While the timeline for steady-state DER modeling appears reasonable, dynamic model data for many existing DERs and

inverter-based resources (IBRs) is currently unavailable. Additionally, if it is determined that multiple types of IBRs are served by the same substation, utilities like Seattle City Light must ensure that their power system analysis software can accommodate this complexity. Given these challenges, Seattle City Light requests additional time to implement dynamic modeling, particularly for unregistered IBRs. · The term “Unregistered IBR” is not clearly defined in the current revision of the standard. Seattle City Light recommends that a formal definition be added to the NERC Glossary of Terms to promote consistent understanding and interpretation across all applicable entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Per Order 901, P 226, “[w]e 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.” The DT has provided industry with the best time available to allow for the Milestone 4 project implementation time to be implemented by 2030.. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase “Bulk-Power System” from this description to remove any potential for ambiguity in application.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

TVA appreciates the efforts by the standard draft team. In addition to the comments provided above, TVA believes that an effort of this magnitude in acquiring model data for unregistered IBRs and aggregate DERs will likely take considerable time and iterations. The implementation plan only allows 12 months after the effective date of the Reliability Standard. That is not sufficient time to attempt to acquire modeling data and parameters, fail to do so, and then develop estimated values with technical justifications. TVA recommends extending the implementation of R2, R3, and R4 to 36 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Per Order 901, P 226, "[w]e 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." The DT has provided industry with the best time available to allow for the Milestone 4 project implementation time to be implemented by 2030..	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	
Comment	
We would want to inquire how power limited and inadvertant export capabilities would be captured. For example if the aggregate DER was 5 MW but 4 MW was power limited it implies that we would need to do gross load and name plate of DER, but how would power controlled systems be reported, especially for dynamic behavior where most distribution or rooftop systems may inadvertanekty export for up to 30 seconds or create load swings for that period of time	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The fluctuations described in the comment could exist and present reporting challenges even without the proposed modifications to MOD-032. The DT believes that explicit reporting of aggregate DER data will allow planners to consider more relevant sensitivities and assumptions about potential DER impacts to BES reliability.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	
Document Name	
Comment	
Black Hills Corporation does not agree with the Implementation Plan because the “ERO Approved Criteria for Acceptable Models” document may not align with FERC order 901 directives. We agree this document could be responsible for the Model Library and processes needed to submit proposed additions, however the model criteria should be controlled through enforceable requirements within each Reliability Standard.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. The DT moved the process of the ERO Approved Criteria for Acceptable Models document process into the standard and models can only be added to the unacceptable list by following the process. If edits are ever needed to the processes, it will be completed through the standards development process where industry is afforded the opportunity to comment and ballot on the process changes. Please see the modifications to the MOD-032-2 standard along with the ERO Unacceptable Models List document.

Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	

(1) Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)).

(2) In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement?

(3) TOP-003 and IRO-010 standards pertain to the data specification and exchange requirements for Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Time Horizons for requirements within MOD-032-2 [Long-Term Planning] and TOP-003-8/IRO-010-7 [Operations Planning] should align with each other. Models created in MOD-032-2 will be utilized for Operations Planning and Real-time Assessments. As such, data exchange requirements in the form of “model submissions” should reflect all valid time frames, including entities that need to receive this data as part of their required assessments.

(4) Attachment 1, Column #2 (item 7(a)) IBR behaviors [remove "capabilities"] related to momentary cessation, tripping, Ride-through, and frequency control

(5) Attachment 1, Column #2 (items 7(a) and 10(a)). Although there are provisions for representing voltage and frequency protection settings in positive sequence simulations, the terms “momentary cessation, tripping, and ride-through” are too ambiguous. These concepts may not be fully representable in positive sequence phasor domain simulations and lack the necessary clarity to ensure compliance.

(6) Attachment 1, Column #2, Item 10: The MRO NRFS recommends establishing a MW threshold level for requiring unregistered IBRs, as determined by the Planning Coordinator (PC) and Transmission Planner (TP) in R1. Additionally, due to the lack of standardized distribution

DER performance requirements, accurately representing the behaviors of unregistered Aggregate Distributed Energy Resources (DER) in sections 10(a) and 10(b) may be challenging. We recommend including “estimated, assumed, or typical DER behaviors related to momentary cessation, tripping, ride-through, voltage control, frequency control, and voltage and frequency protection settings.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1. R2.2 was added to require that facility owners provide models that have been verified and validated in accordance with MOD-026 if available. 2. The DT views this information as included in the sequence data already required under the Short Circuit column. The PC/TP can request this additional detail if deemed necessary, but such specific additions to the Short Circuit column are not within the scope of any of the SARs assigned to Project 2022-02. 3. Models used in operations should be consistent with those used in planning as applicable. The inclusion of “as applicable” allows for variation as necessary for application in the operations horizon. One example where consistent models would not be appropriate is an update made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation. 4. The DT views the two terms as nearly synonymous within the context of Attachment 1, so the DT did not see a compelling reason to make the proposed change. 5. The terms “momentary cessation, tripping, and ride-through” are specifically used in FERC Order 901; the DT felt it was important to mirror the FERC 901 language where possible. 6. The proposed footnote 7 is intended to allow the PC/TP to define DER thresholds for a local area if appropriate. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather unregistered IBR or DER data.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

In MOD-032-2 Attachment 1, Data Reporting Requirements, item #10 under steady-state requirements (see below) should be removed. It is an open and unrestricted invitation to request data which has no practical value in assessing transmission system performance. As a result, time and resources will be wasted for no benefit. "10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]"

Likes 0	
Dislikes 0	

Response
Thank you for the comment. The DT believes that Attachment 1 is intended to establish the minimum sets of data that the PC and TP are required to collect for appropriate power system modeling and analysis. Item #10 appropriately gives the PC/TP the authority to require additional data that is deemed necessary for the local area.

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.

Zenon O'young-Chu - Seattle City Light - 3	
Answer	

Document Name	
Comment	

N/A

Seattle City Light has concerns regarding the proposed implementation timeline for modeling dynamic data for Distributed Energy Resources (DER). While the timeline for steady-state DER modeling appears reasonable, dynamic model data for many existing DERs and inverter-based resources (IBRs) is currently unavailable. Additionally, if it is determined that multiple types of IBRs are served by the same substation, utilities like Seattle City Light must ensure that their power system analysis software can accommodate this complexity. Given these challenges, Seattle City Light requests additional time to implement dynamic modeling, particularly for unregistered IBRs.

The term “Unregistered IBR” is not clearly defined in the current revision of the standard. Seattle City Light recommends that a formal definition be added to the NERC Glossary of Terms to promote consistent understanding and interpretation across all applicable entities.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Per Order 901, P 226, “[w]e 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.” The DT has provided industry with the best time available to allow for the Milestone 4 project implementation time to be implemented by 2030..

In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase “Bulk-Power System” from this description to remove any potential for ambiguity in application.

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO	
Answer	
Document Name	
Comment	

1. Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)).

2. In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement?

3. TOP-003 and IRO-010 standards pertain to the data specification and exchange requirements for Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Time Horizons for requirements within MOD-032-2 [Long-Term Planning] and TOP-003-8/IRO-010-7 [Operations Planning] should align with each other. Models created in MOD-032-2 will be utilized for Operations Planning and Real-time Assessments. As such, data exchange requirements in the form of “model submissions” should reflect all valid time frames, including entities that need to receive this data as part of their required assessments.

4. Attachment 1, Column #2 (item 7(a)) IBR behaviors capabilities related to momentary cessation, tripping, Ride-through, and frequency control

5. Attachment 1, Column #2 (items 7(a) and 10(a)). Although there are provisions for representing voltage and frequency protection settings in positive sequence simulations, the terms “momentary cessation, tripping, and ride-through” are too ambiguous. These concepts may not be fully representable in positive sequence phasor domain simulations and lack the necessary clarity to ensure compliance.

6. Attachment 1, Column #2, Item 10: The MRO NSRF recommends establishing a MW threshold level for requiring unregistered IBRs, as determined by the Planning Coordinator (PC) and Transmission Planner (TP) in R1. Additionally, due to the lack of standardized distribution DER performance requirements, accurately representing the behaviors of unregistered Aggregate Distributed Energy Resources (DER) in sections 10(a) and 10(b) may be challenging. We

recommend including “estimated, assumed, or typical DER behaviors related to momentary cessation, tripping, ride-through, voltage control, frequency control, and voltage and frequency protection settings.”

Please see attached document for additional information	
Likes 2	Scott Brame, N/A, Brame Scott; Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Thank you for your comments.
1. R2.2 was added to require that facility owners provide models that have been verified and validated in accordance with MOD-026 if available.
2. The DT views this information as included in the sequence data already required under the Short Circuit column. The PC/TP can request this additional detail if deemed necessary, but such specific additions to the Short Circuit column are not within the scope of any of the SARs assigned to Project 2022-02.
3. Models used in operations should be consistent with those used in planning as applicable. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. One example where consistent models would not be appropriate is an update made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation.
4. The DT views the two terms as nearly synonymous within the context of Attachment 1, so the DT did not see a compelling reason to make the proposed change.
5. The terms "momentary cessation, tripping, and ride-through" are specifically used in FERC Order 901; the DT felt it was important to mirror the FERC 901 language where possible.
6. The proposed footnote 7 is intended to allow the PC/TP to define DER thresholds for a local area if appropriate. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather unregistered IBR or DER data.

Brooke Jockin - Portland General Electric Co. - 1, Group Name Portland General Electric Co.

Answer	
Document Name	

Comment

Portland General Electric (PGE) supports the Western Power Pool's comments.

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Carver Powers - Utility Services, Inc. - 4	
Answer	
Document Name	
Comment	

Both proposed standards (MOD-032-2; MOD-033-3) purport to define unregistered IBRs in a footnote (i.e., footnote 1 of each), with draft MOD-032-2 limiting its applicability with the phrase "as used in this standard." Footnote treatment seems ill-suited to a definition that must be used consistently in a set of Milestone 3 and 4 standards to enable the data, modeling, planning and operational studies that are intended to be developed on a consistent basis to produce the reliability benefits Order 901 expressly contemplated. *See, e.g.,* Order 901, P 53. To better ensure consistent usage throughout the relevant standards, an appropriate unregistered IBR definition should be added to the Glossary. Indeed, inclusion of the unregistered IBR definition in a footnote is inconsistent with the proposal to include the DER definition in the Glossary.

In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application.

Moreover, to the extent the MOD-032-2 Technical Rationale explanation is meant to inform the "unregistered IBRs" footnote, it fails to remedy the concern that there is no precise definition of Bulk-Power System that would enable a clean delineation of the IBR resources whose data is to be provided. The statutory term "bulk-power system," like "local distribution," is pertinent to the boundaries of FERC's jurisdiction, and as stated in Order No. 773, "[t]he determination whether an element or facility is 'used in local distribution,' as the phrase is used in the FPA, requires a jurisdictional analysis that is more appropriately performed by the Commission." *Revisions to Elec. Reliability Org.*

Definition of Bulk Elec. Sys. & Rules of Proc., Order No. 773, 141 FERC ¶ 61,236, P 69 (2012), *clarified on reh'g,* Order No. 773-A, 143 FERC ¶ 61,053, *compliance deadline extended,* 143 FERC ¶ 61,231, *clarified,* 144 FERC ¶ 61,174 (2013), *review denied sub nom. New York v. FERC*, 783 F.3d 946 (2d Cir. 2015).

In approving NERC's criteria for fulfilling the directives to register IBRs that are "connected to the Bulk-Power System and that have an aggregate material impact on the reliable operation of the Bulk-Power System," FERC found it reasonable for NERC to use "non-BES Inverter-Based Resource(s) 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." *N. Am. Elec. Reliability Corp.*, 187 FERC ¶ 61,196, PP 10, 36-39 (2024). At the same time, FERC reiterated that determining the scope of the BPS is its call to make. *Id.* P 54 n.127. *See also id.* P 44.

Given FERC's acceptance of the 60 kV cutoff as described above for Category 2 GO/GOP registration purposes as sufficient to meet its "connected to the BPS" directive, and Project 2024-01's use of that same cut off for purposes of the GO/GOP Category 2 Glossary definitions (which recently received more than the requisite votes needed for approval), there is no reason for the proposed MOD-032-2 and MOD-033-3 footnotes to use vague BPS terminology. Instead, "unregistered IBR" should be added to the Glossary and defined using the already approved proxies for "BPS-connected," *e.g.*: "non-BES Inverter-Based Resource(s) that do not 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."

Context for and a summary of all concerns with the proposed MOD-032-2 definitions are provided in Question 1; additional concerns are provided in response to Questions 4 and 5.

Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	

Response

Thank you for your comment. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
In MOD-032-2, Requirement 2.1 points to R1 part 1.1 which is attachment 1. Requirement 1 & 2 only mentions IBR but attachment 1 contains language about Wind plant type 1 & 2. From NERC definition Type 1 and 2 machines are not considered IBR. Therefore, this section needs to be carefully reworded to reduce ambiguity and confusion. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Requirement 2.1 was revised to eliminate a specific reference to Requirement 1.1 and only allows data estimations for unregistered IBR and DER. Project 2022-02 does not have any assigned SAR to address reliability issues associated with gathering data for type 1 and type 2 wind plants or synchronous machines that are not IBR or DER. The reference to type 1 and type 2 wind plants was added in Attachment 1 to maintain the status quo for such facilities with the addition of a specific line item for IBR to address FERC Order 901.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	
Document Name	
Comment	
NIPSCO supports MISO's comments below: "For short-circuit modeling under Item 3 of Attachment 1, Generator Owners (GOs) should be required to submit models that reflect their specific resource type, for example, synchronous generators versus inverter-based resources. Relying solely on positive, negative, and zero sequence data may be insufficient for accurately representing inverter-based resources, which often require more detailed modeling parameters." "Regarding steady-state generation (Item 3), there is no need to distinguish between generating units and storage resources, as batteries and pumped storage units are already categorized as generators. If the drafting team wishes to explicitly include storage resources, this clarification would be better suited as a footnote rather than a separate classification."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Submission of resource type information is included under steady state item 3. The PC/TP can request additional detail if deemed necessary, but such specific additions to the Short Circuit column are not within the scope of any of the SARs assigned to Project 2022-02.	

Within industry, storage facilities with both real power injection and real power absorption capabilities are often considered distinct from generators that only have real power injection capabilities. Therefore, the DT believes it is appropriate to explicitly include both facilities in steady state item 3.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
In MOD-032-2, Requirement 2.1 points to R1 part 1.1 which is attachment 1. Requirement 1 & 2 only mentions IBR but attachment 1 contains language about Wind plant type 1 & 2. From NERC definition Type 1 and 2 machines are not considered IBR. Therefore, this section needs to be carefully reworded to reduce ambiguity and confusion. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement 2.1 was revised to eliminate a specific reference to Requirement 1.1 and only allows data estimations for unregistered IBR and DER. Project 2022-02 does not have any assigned SAR to address reliability issues associated with gathering data for Type 1 and Type 2 wind plants or synchronous machines that are not IBR or DER. The reference to type 1 and type 2 wind plants was added in Attachment 1 to maintain the status quo for such facilities with the addition of a specific line item for IBR to address FERC Order 901.	
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; Kris Kirkegaard, 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
SMUD and BANC feel that the implementation plan for MOD-032-2 is too restrictive when it comes to implementing new dynamic data for the many new generation assets being added to the scope of MOD-032-2 (e.g. aggregate DER and unregistered IBR). We support the comments submitted by Tacoma Power that justify more time being added for entities to meet compliance and suggest that a 24-to-36-month implementation plan is appropriate. Lastly, we encourage the standards drafting team (SDT) to refrain from creating a definition in a footnote. The changes proposed in MOD-032-2 and the initial ballot of MOD-033-3 both define the term “unregistered IBR” in a footnote. This important term could very well be used in additional Standards when the Milestone 4 directives are addressed and, therefore, should be defined in a formal definition included in the Glossary of Terms Used in the NERC Reliability Standards (NERC Glossary). A Standards Authorization Request was drafted to create a formal definition for “unregistered IBR”. The SDT should work with NERC and the SDT for MOD-033-3 to ensure the same definition is being used for this term and that it is formally included in the NERC Glossary.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response
Thank you for your comment. Per Order 901, P 226, “[w]e 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.” The DT has provided industry with the best time available to allow for the Milestone 4 project implementation time to be implemented by 2030. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase “Bulk-Power System” from this description to remove any potential for ambiguity in application.

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	

Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)).

In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement?

TOP-003 and IRO-010 standards pertain to the data specification and exchange requirements for Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. Time Horizons for requirements within MOD-032-2 [Long-Term Planning] and TOP-003-8/IRO-010-7 [Operations Planning] should align with each other. Models created in MOD-032-2 will be utilized for Operations Planning and Real-time Assessments. As such, data exchange requirements in the form of “model submissions” should reflect all valid time frames, including entities that need to receive this data as part of their required assessments.

Attachment 1, Column #2 (item 7(a)) IBR behaviors related to momentary cessation, tripping, Ride-through, and frequency control	
Likes 0	
Dislikes 0	

Response

Thank you for the comments.

R2.2 was added to require that facility owners provide models that have been verified and validated in accordance with MOD-026 if available.

The DT views this information as included in the sequence data already required under the Short Circuit column. The PC/TP can request this additional detail if deemed necessary, but such specific additions to the Short Circuit column are not within the scope of any of the SARs assigned to Project 2022-02.

Models used in operations should be consistent with those used in planning as applicable. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. One example where consistent models would not be appropriate is an update made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation.

Pirouz Honarmand - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

When the DER data is not available the SDT suggests estimating it. Is it possible to include technical rationale and guidance to help entities to proceed with this estimate? The guide should help entities to apply and use consistent estimating approaches.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The FERC Order 901 directed NERC to require estimations when unable to gather data. Please see the updated technical rationale, which provides additional information on data estimation.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
We support the NPCC RSC comments Comments pertaining to IRO-010: R3 Lower VSL: Missing "R1". Should read "…to meet one of the parts of R1, Part 1.5" as used in the Moderate and High VSL. Furthermore, there is a space missing between R1 and Part 1.5 in the Moderate VSL. M3: Reliability Coordinator is listed twice in the measure. C1.2: Suggest adding "and information" to the 2nd bullet to better reflect R2 and M2. As posted, it currently reads "The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2". Suggest changing to "The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2".	
Likes 0	
Dislikes 0	

Response	
Thank you. Please see the DT's response to NPCC RSC.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE noticed the implementation plan could provide more clarity on the retirement dates, initial performance dates, and phased-in compliance dates. First, Texas RE noticed the retirement date for MOD-032-2 is "immediately prior" to the effective date of the standard. The initial performance and compliance dates, however, are 12 months after the effective date of the standard. Texas RE is concerned this could be interpreted to leave a gap in compliance for 12 months. The drafting team may be attempting to address this in the last paragraph of page 3, "Entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032- 2", although it is not clear that verbiage is referring to that potential gap between the effective date of the standard and the phased-in compliance dates.

Texas RE also inquires as to the difference in initial performance dates and compliance dates. This implementation plan seems to describe them in the same way. It is Texas RE's understanding, however, that the initial performance date is for periodic requirements, so registered entities (and auditors) know when the first time the action is to take place, and thus start the periodic tracking of the activity. Compliance dates, on the other hand, refer to phased-in dates after the effective date of the standard so registered entities have time to complete certain activities. Is the intent of the initial performance date to refer to the periodicity in Requirement Part 1.3? There do not appear to be periodic activities in Requirements R2, R3, and R4, and thus a compliance date (phased-in dates) would be appropriate for those requirements.

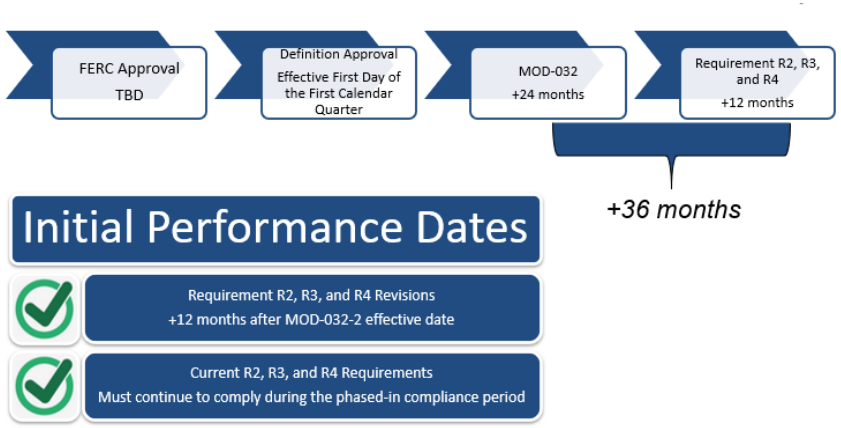
Additionally, Texas RE noticed that the VRFs are included in the VSL table for IRO-010-6, but are not in the VSL tables for MOD-032-2 and TOP-003-8. The VRFs do appear to be in the requirements for all proposed standards.

Lastly, Texas RE requests the SDT consider adding the “ERO Approved Criteria for Acceptable Models” to the Associated Documents section of each standard (Section E for MOD-032-2, Section F for IRO-010-6 and TOP-003-8).

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
MOD-032-2 will become effective 24 months after the effective date of the applicable governmental authority’s order approving the standard. This is the date by which Planning Coordinators and Transmission Planners must develop revised data requirements and reporting procedures that meet the revised requirements of MOD-032-2. The compliance date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4 will be 12 months following the effective date (or 36 months following regulatory approval). This is to allow reporting entities sufficient time to respond to the revised data requirements and reporting procedures. Please see diagram below.



The VRFs have been removed from the VSL table in IRO-010-6 to reflect the correct updated template. The DT thanks you for identifying this update needed.

The process which must be followed to revise the Unacceptable Models List document is established and maintained in the MOD-032 supporting document.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 5, 6, 1; Mathew Weber, Salt River Project, 3, 5, 6, 1; Matthew Jaramilla, Salt River Project, 3, 5, 6, 1; Timothy Singh, Salt River Project, 3, 5, 6, 1; - Israel Perez	
Answer	
Document Name	
Comment	
Please clarify if residential roof top solar will be subject to order and study criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Residential roof top solar is considered DER per the proposed DER definition, and in aggregate will be required to be included in data collection processes in accordance with MOD-032-2.	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
Comments pertaining to IRO-010: R3 Lower VSL: Missing “R1”. Should read “…to meet one of the parts of R1, Part 1.5” as used in the Moderate and High VSL. Furthermore, there is a space missing between R1 and Part 1.5 in the Moderate VSL. M3: Reliability Coordinator is listed twice in the measure.	

C1.2: Suggest adding “and information” to the 2nd bullet to better reflect R2 and M2. As posted, it currently reads “The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2”. Suggest changing to “The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. R3 Lower VSL – correction has been made. Please see updated standard. M3: The second Reliability Coordinator has been removed from the measure. C1.2. The DT added the word “and” to be consistent with the other bullets.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	
Document Name	
Comment	
1. Attachment 1; Column #2 recommend adding the following (For the in-service item provide verified and validated dynamics model(s)). 2. In the “Short Circuit” column of MOD-032-2 attachment 1, perhaps “transformer winding connection information” should be added as another data requirement? 3. TOP-003 and IRO-010 standards pertain to the data specification and exchange requirements for Transmission Operators, Balancing Authorities and Reliability Coordinators to perform their Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	

Time Horizons for requirements within MOD-032-2 [Long-Term Planning] and TOP-003-8/IRO-010-7 [Operations Planning] should align with each other. Models created in MOD-032-2 will be utilized for Operations Planning and Real-time Assessments. As such, data exchange requirements in the form of "model submissions" should reflect the valid time frames, including entities that need to receive this data as part of their required assessments.

4. Add the following in **bold**, and remove the following in *italics:*

Attachment 1, Column #2 (item 7(a)) IBR **behaviors** *capabilities* related to momentary cessation, tripping, Ride-through, and frequency control.

5. Attachment 1, Column #2 (items 7(a) and 10(a)). Although there are provisions for representing voltage and frequency protection settings in positive sequence simulations, the terms "momentary cessation, tripping, and ride-through" are too ambiguous. These concepts may not be fully representable in positive sequence phasor domain simulations and lack the necessary clarity to ensure compliance.

6. Attachment 1, Column #2, Item 10: ITC recommends establishing a MW threshold level for requiring unregistered IBRs, as determined by the Planning Coordinator (PC) and Transmission Planner (TP) in R1. Additionally, due to the lack of standardized distribution DER performance requirements, accurately representing the behaviors of unregistered Aggregate Distributed Energy Resources (DER) in sections 10(a) and 10(b) may be challenging. We recommend including "estimated, assumed, or typical DER behaviors related to momentary cessation, tripping, ride-through, voltage control, frequency control, and voltage and frequency protection settings."

Likes 0	
Dislikes 0	

Response

1. R2.2 was added to require that facility owners provide models that have been verified and validated in accordance with MOD-026 if available.
2. The DT views this information as included in the sequence data already required under the Short Circuit column. The PC/TP can request this additional detail if deemed necessary, but such specific additions to the Short Circuit column are not within the scope of any of the SARs assigned to Project 2022-02.
3. Models used in operations should be consistent with those used in planning as applicable. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. One example where consistent models would not be appropriate is an

update made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation.

4. The DT views the two terms as nearly synonymous within the context of Attachment 1, so the DT did not see a compelling reason to make the proposed change.
5. The terms “momentary cessation, tripping, and ride-through” are specifically used in FERC Order 901. The DT felt it was important to mirror the FERC 901 language where possible.
6. The proposed footnote 7 is intended to allow the PC/TP to define DER thresholds for a local area if appropriate. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather unregistered IBR or DER data.

Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Kirsten Rowley - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council (IRC) Standards Review Committee (SRC)	
Answer	
Document Name	2022-02_Unofficial_Comment_Form_Initial_Posting_April_17_2025_SRC Final Draft.docx
Comment	
ERCOT, Midcontinent ISO, Southwest Power Pool, and California ISO abstain from the response to this question.	

For short-circuit in Attachment 1 under item 3, the GO should be required to submit a model based on their resource type i.e. synchronous generator versus inverter based. Positive, negative and zero sequence data may not cover all required modeling data for inverter-based resources. For Steady State generation (item #3), there is no need to separate between generating units and storage units as battery and pumped storage resources are considered generators. If the drafting team wants to clarify that storage units are included, then that should be a footnote.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Submission of resource type information is included under steady state item 3. The PC/TP can request additional detail if deemed necessary, but such specific additions to the Short Circuit column are not within the scope of any of the SARs assigned to Project 2022-02. Within industry, storage facilities with both real power injection and real power absorption capabilities are often considered distinct from generators that only have real power injection capabilities. Therefore, the DT believes it is appropriate to explicitly include both facilities in steady state item 3.	
Colten Mitchell - Indiana Municipal Power Agency - 4	
Answer	
Document Name	
Comment	
Both proposed standards (MOD-032-2; MOD-033-3) purport to define unregistered IBRs in a footnote (i.e., footnote 1 of each), with draft MOD-032-2 limiting its applicability with the phrase “as used in this standard.” Footnote treatment seems ill-suited to a definition that must be used consistently in a set of Milestone 3 and 4 standards to enable the data, modeling, planning and operational studies that are intended to be developed on a consistent basis to produce the reliability benefits Order 901 expressly contemplated. *See, e.g.,* Order 901, P 53. To better ensure consistent usage throughout the relevant standards, an appropriate unregistered IBR definition should be added to the	

Glossary. Indeed, inclusion of the unregistered IBR definition in a footnote is inconsistent with the proposal to include the DER definition in the Glossary.

In addition, the proposed footnote explanations of unregistered IBRs improperly use the term "Bulk-Power System connected" to delineate the IBRs to be covered. That term lacks the precision necessary for the registered entities (i.e., Transmission Owners and Distribution Providers) that are required to provide individualized data on such entities (proposed MOD-032-2, R2), and PCs, RCs, and TOPs that are required to validate system models using this data "to facilitate achieving and maintaining adequate model accuracy" (proposed MOD-033-3, Purpose), or to provide confidence that the resulting reporting will consistently produce results that do not reflect gaps or double counting of IBRs. While the MOD-032-2 Technical Rationale, at 4, suggests that "bulk system-connected" can be shorthand for resources connected to the transmission system, it does not provide a controlling interpretation of the term "Bulk-Power System connected," as used in the proposed standard, that can be consistently applied and relied upon.

Moreover, to the extent the MOD-032-2 Technical Rationale explanation is meant to inform the "unregistered IBRs" footnote, it fails to remedy the concern that there is no precise definition of Bulk-Power System that would enable a clean delineation of the IBR resources whose data is to be provided. The statutory term "bulk-power system," like "local distribution," is pertinent to the boundaries of FERC's jurisdiction, and as stated in Order No. 773, "[t]he determination whether an element or facility is 'used in local distribution,' as the phrase is used in the FPA, requires a jurisdictional analysis that is more appropriately performed by the Commission." *Revisions to Elec. Reliability Org. Definition of Bulk Elec. Sys. & Rules of Proc.,* Order No. 773, 141 FERC ¶ 61,236, P 69 (2012), *clarified on reh'g,* Order No. 773-A, 143 FERC ¶ 61,053, *compliance deadline extended,* 143 FERC ¶ 61,231, *clarified,* 144 FERC ¶ 61,174 (2013), *review denied sub nom. New York v. FERC*, 783 F.3d 946 (2d Cir. 2015).

In approving NERC's criteria for fulfilling the directives to register IBRs that are "connected to the Bulk-Power System and that have an aggregate material impact on the reliable operation of the Bulk-Power System," FERC found it reasonable for NERC to use "non-BES Inverter-Based Resource(s) 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." *N. Am. Elec. Reliability Corp.*, 187 FERC ¶ 61,196, PP 10, 36-39 (2024). At the same time, FERC reiterated that determining the scope of the BPS is its call to make. *Id.* P 54 n.127. *See also id.* P 44.

Given FERC's acceptance of the 60 kV cutoff as described above for Category 2 GO/GOP registration purposes as sufficient to meet its "connected to the BPS" directive, and Project 2024-01's use of that same cut off for purposes of the GO/GOP Category 2 Glossary definitions (which recently received more than the requisite votes needed for approval), there is no reason for the proposed MOD-032-2 and MOD-033-3 footnotes to use vague BPS terminology. Instead, "unregistered IBR" should be added to the Glossary and defined using the already approved

proxies for “BPS-connected,” *e.g.*: “non-BES Inverter-Based Resource(s) that do not 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.” Context for and a summary of all concerns with the proposed MOD-032-2 definitions are provided in Question 1; additional concerns are provided in response to Questions 4 and 5.	
Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	
Thank you for your comments. In response to comments, the drafting team has removed reference to the phrase "unregistered IBR" from the requirement text and replaced it with the descriptive text formerly in the footnote. Former references to "unregistered IBR" now refer to IBRs that are not Distributed Energy Resources, as the drafting team proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as either category 1 or category 2). As suggested by commenters, the drafting team has removed the phrase “Bulk-Power System” from this description to remove any potential for ambiguity in application. The proposed footnote 7 is intended to allow the PC/TP to define DER thresholds for a local area if appropriate. R2.1 specifically allows estimations when the responsible entity as identified by the PC/TP is unable to gather unregistered IBR or DER data.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Several ACES Members have expressed their concerns regarding their ability to collect and submit all of the information identified in the proposed draft of MOD-032-2, particularly the proposed dynamic data. Therefore, ACES suggests that the drafting team should consider a minimum threshold value for dynamic DER data. In our opinion, such a threshold would be consistent with NERC’s precedent for developing risk-based Reliability Standards and would prevent an insurmountably large compliance being placed upon the applicable registered entities.	

PPI generally agrees with these comments, with one exception. In regard to question 2, we believe the TP, not the TO, should be the entity responsible for estimating DER data, as the TP is currently responsible for submitting load forecasts and similar data. DER's are essentially negative load. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The proposed footnote 7 is intended to allow the PC/TP to define DER thresholds for a local area if appropriate.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	Project 2022-02 _ EEI Near Final Draft Comments _ MOD-032 IRO-10 TOP-002 Draft 1_ Rev. 0h _ 5_14_2025 (1).docx
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

For this question, ERCOT does not join the comments submitted by the IRC SRC.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Scott Thompson - TXNM Energy - 3	
Answer	
Document Name	
Comment	
This project incoporates many definitions or soon to be definitions that have been or will be changed. It would be nice if all of the SDT's from all of the FERC order 901 projects would get together and form a concise voice and vision on how to incorporate those new definitions into these new and modified standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. All milestone 3 projects have coordinated and requested review of definitions being developed for the modified standards.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	

It will likely require industry more than three years to comply with MOD-032-2, so the three year timeline proposed in the Implementation Plan should be extended. The Consideration of FERC Order 901 Directives document notes: "It is understood that based on what is being required via MOD-032, industry would need at least one year to gather data, hold meetings with respective OEM or developers to gather models needed, and then an additional two years to update models based on the ERO Approved Criteria for Acceptable Models document, etc." As was established at length in the September 2024 PRC-029 technical workshop and recent industry comments on FERC's Notice of Proposed Rulemaking to approve PRC-029, coordination with OEMs is challenging and time consuming, particularly for vintage generator technology that is no longer supported. The Consideration of FERC Order 901 Directives document notes the uncertainty in the timeline for that process, noting that initial OEM coordination may take "at least one year." Extending the effective date should still allow NERC to meet the 2030 deadline FERC suggested in Order 901. This will ensure model development is not rushed, which could potentially endanger reliability if models are not adequately vetted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order 901 requires all standard creation and modifications to be in effect by 2030. For milestone 4 to meet this FERC directed requirement, this is the most time that can be allotted for MOD-032 to allow the next project time to meet the FERC directive.	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Hydro One Networks, Inc. - 1 - NPCC	
Answer	
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	
Document Name	
Comment	
Seminole Electric Cooperative's commment is that the DER definition does not guarantee that the resource(s) included influence the BPS that is in federal jurisdiction. The current definition may place unnecessary compliance burden on local distribution that is under state authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Definitions in themselves do not create any compliance burden. The DER definition simply provides a resource classification based on its connection to a distribution system.	
Jens Boemer - Electric Power Research Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
I. Introduction 1. The Electric Power Research Institute (EPRI)[1] respectfully submits these comments (This Response) in response to North American Electric Reliability Corporation (NERC)'s request for formal comment on Project 2022-02 Uniform Modeling Framework for IBR, issued April 17, 2025. 2. EPRI closely collaborates with its members inclusive of electric power utilities, Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs), as well as numerous other stakeholders, domestically and internationally. In its role, EPRI conducts independent research and development relating to the generation, delivery, and use of electricity for public benefit by working to help make	

electricity more reliable, affordable and environmentally safe. EPRI's comments on this topic are technical in nature based upon EPRI's research, development, and demonstration experience over the last 50 years in planning, analyzing, and developing technologies for electric power.

3. EPRI research and technology transfer deliverables are generally accessible on its website to the public, either for free or for purchase, and occasionally subject to licensing, export control, and other requirements.[2] The publicly available and free-of-charge milestone reports from a U.S. Department of Energy (DOE)- and EPRI member-funded research project, Adaptive Protection and Validated Models to Enable Deployment of High Penetrations of Solar PV ("PV-MOD"), [3] and other research deliverables substantiate many of the comments made in This Response.

4. While not a standards development organization (SDO), EPRI conducts research and demonstration projects in relevant areas as well as facilitates knowledge transfer and collaboration that SDOs may, at times, use to inform technical and regulatory standards development, such as in Institute of Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), International Council on Large Electric Systems (CIGRE), and NERC.[4]

II. Conclusion

5. EPRI appreciates the opportunity to provide NERC with its technical recommendations and comments on these important topics related to Reliability Standards for IBRs. EPRI looks forward to working with its members, NERC, and other stakeholders on providing further independent technical information on these important questions.

III. Contact Information

Jens C. Boemer, Technical Executive

Email: JBoemer@epri.com

[1] EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax-exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1996, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

[2] https://www.epri.com (last accessed, May 16, 2025)

[3] PV-MOD Project Website. EPRI. Palo Alto, CA: 2024. [Online] https://www.epri.com/pvmod (last accessed, May 16, 2025)

[4] For transparency, we would like to disclose that EPRI collaborates with other organizations such as IEEE, IEC, CIGRE, and NERC; however, EPRI is not a regulatory- or standard-setting organization. EPRI research is often considered in the development of recommendations, guidelines, and best practices that are not determinative.

Likes 0	
Dislikes 0	

Response

Thank you for your comments and information.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder
Standards Announcement
Project 2022-02 Uniform Modeling Framework for IBR

Initial Ballots and Non-binding Polls Open through May 16, 2025

Now Available

Initial Ballots and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, May 16, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- 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, Jordan Mallory (via email) or at 470-479-7538. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR observer list” in the Description Box.



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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Formal Comment Period Open through May 16, 2025
Ballot Pools Forming April 17 – 28, 2025

Now Available

A formal comment period for **Project 2022-02 Uniform Modeling Framework for IBR**, is open through **8 p.m. Eastern, May 16, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- 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, Monday, April 28, 2025.** 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 standards and implementation plan, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **May 7 – 16, 2025**.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 470-479-7538. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR observer list” in the Description Box.

North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
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Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 IN 1 ST
Voting Start Date: 5/7/2025 12:01:00 AM
Voting End Date: 5/16/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 280
Quorum: 87.86
Quorum Established Date: 5/16/2025 2:26:01 PM
Weighted Segment Value: 39.05

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	21	0.333	42	0.667	0	3	6
Segment: 2	7	0.6	1	0.1	5	0.5	0	0	1
Segment: 3	66	1	22	0.393	34	0.607	0	2	8
Segment: 4	14	1	6	0.545	5	0.455	0	1	2
Segment: 5	68	1	16	0.296	38	0.704	0	3	11
Segment: 6	47	1	11	0.275	29	0.725	0	2	5
Segment: 7	0	0	0	0	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	1	1
Totals:	280	6	81	2.343	153	3.657	0	12	34

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
1	TXNM Energy	Lynn Goldstein		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	American Municipal Power	Amy Ritts		Negative	Third-Party Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted

3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Sing Tay		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Black Hills Corporation	Josh Schumacher		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
1	Black Hills Corporation	Trevor Rombough		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
					Third-

1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Party Comments
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	Third-Party Comments
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments

6	Austin Energy	Imane Mrini		None	Submitted N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
5	Leeward Renewable Energy	Rob Robertson		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Entergy	James Keele		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted

10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber		Negative	Comments Submitted
1	Salt River Project	Laura Somak		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Kirsten Rowley		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
4	Western Power Pool	Kevin Conway		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A

3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Negative	Third-Party Comments
6	Ameren - Ameren Services	Robert Quinlivan	Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano	Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary	Negative	Third-Party Comments
5	Orsted Americas	Keith Smith	None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal	Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden	Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Erin Doane	Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas	Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville	Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea	Negative	Third-Party Comments
6	AEP	Randy Calhoun	Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A

5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Negative	Third-Party Comments
1	National Grid USA	Jacqueline Ryan		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A

1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
1	Seattle City Light	Michael Jang		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Negative	Third-Party Comments
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Abstain	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Third-Party Comments
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A

3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		None	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Salt River Project	Matthew Jaramilla		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
5	Muscatine Power and Water	Chance Back		None	N/A
3	TXNM Energy	Scott Thompson		Negative	Comments Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments

1	Entergy	Brian Lindsey		Negative	Submitted Comments
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
4	Seattle City Light	Robert Jones		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
6	Basin Electric Power Cooperative	Eve G Stromer		Negative	Third-Party

5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	Comments N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted



Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 IN 1 ST
Voting Start Date: 5/7/2025 12:01:00 AM
Voting End Date: 5/16/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 246
Total Ballot Pool: 281
Quorum: 87.54
Quorum Established Date: 5/16/2025 2:26:24 PM
Weighted Segment Value: 41.62

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	73	1	26	0.426	35	0.574	0	5	7
Segment: 2	7	0.6	1	0.1	5	0.5	0	0	1
Segment: 3	66	1	24	0.436	31	0.564	0	3	8
Segment: 4	14	1	4	0.364	7	0.636	0	1	2
Segment: 5	68	1	21	0.412	30	0.588	0	6	11
Segment: 6	47	1	14	0.359	25	0.641	0	3	5
Segment: 7	0	0	0	0	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	1	1
Totals:	281	6	94	2.497	133	3.503	0	19	35

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
1	TXNM Energy	Lynn Goldstein		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A

5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Sing Tay		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Black Hills Corporation	Josh Schumacher		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
1	Black Hills Corporation	Trevor Rombough		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted

1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	Third-Party Comments
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
5	Leeward Renewable Energy	Rob Robertson		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments

					Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	Salt River Project	Timothy Singh		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Entergy	James Keele		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber		Affirmative	N/A
1	Salt River Project	Laura Somak		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Kirsten Rowley		Negative	Comments Submitted

1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
4	Western Power Pool	Kevin Conway		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A

1	Southern Company - Southern Company Services, Inc.	Matt Carden	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary	Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
5	Orsted Americas	Keith Smith	None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke	Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal	Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden	Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Erin Doane	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas	Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville	Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea	Negative	Third-Party Comments
6	AEP	Randy Calhoun	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
5	Duke Energy	Dale Goodwine	Negative	Third-Party Comments
1	Exelon	Daniel Gacek	Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin	Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons	Negative	Third-Party Comments
6	Xcel Energy, Inc.	Patrick Flaherty	Negative	Third-Party Comments
1	National Grid USA	Jacqueline Ryan	Negative	Third-Party Comments

6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Negative	Comments Submitted
5	EDF Renewable Energy	Steven Sconce		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Negative	Comments Submitted
2	Independent Electricity System Operator	Pirouz		Affirmative	N/A

1	N.W. Electric Power Cooperative, Inc.	Honarmand Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Abstain	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Third-Party Comments
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		None	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
3	TXNM Energy	Scott Thompson		Negative	Comments Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted

1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
4	Seattle City Light	Robert Jones		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Negative	Third-Party Comments
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	Affirmative	N/A
3	Seattle City Light	Zenon O'young-Chu		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
					Third-

5	PPL - Louisville Gas and Electric Co.	Julie Hostrander	Negative	Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci	Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday	Negative	Comments Submitted

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 IN 1 ST
Voting Start Date: 5/7/2025 12:01:00 AM
Voting End Date: 5/16/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 247
Total Ballot Pool: 281
Quorum: 87.9
Quorum Established Date: 5/16/2025 2:26:46 PM
Weighted Segment Value: 34.7

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	73	1	21	0.344	40	0.656	0	5	7
Segment: 2	7	0.6	1	0.1	5	0.5	0	0	1
Segment: 3	66	1	21	0.375	35	0.625	0	3	7
Segment: 4	14	1	3	0.273	8	0.727	0	1	2
Segment: 5	68	1	17	0.333	34	0.667	0	6	11
Segment: 6	47	1	10	0.256	29	0.744	0	3	5
Segment: 7	0	0	0	0	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	1	1
Totals:	281	6	77	2.082	151	3.918	0	19	34

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Amanda Skubal		Negative	Comments Submitted
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted

3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Sing Tay		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Black Hills Corporation	Josh Schumacher		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
1	Black Hills Corporation	Trevor Rombough		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A

4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	Third-Party Comments
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres		Negative	Third-Party Comments
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Negative	Third-Party

					Comments
3	Manitoba Hydro	Mike Smith		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
5	Leeward Renewable Energy	Rob Robertson		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	Salt River Project	Timothy Singh		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Entergy	James Keele		Negative	Comments Submitted

4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber		Affirmative	N/A
1	Salt River Project	Laura Somak		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Kirsten Rowley		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
4	Western Power Pool	Kevin Conway		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments

3	Snohomish County PUD No. 1	Holly Chaney	Affirmative	Submitted N/A
5	Ameren - Ameren Missouri	Sam Dwyer	Negative	Third-Party Comments
6	Ameren - Ameren Services	Robert Quinlivan	Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano	Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson	Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary	Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	Comments Submitted
5	Orsted Americas	Keith Smith	None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke	Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal	Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden	Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Erin Doane	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas	Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville	Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea	Negative	Third-Party Comments
6	AEP	Randy Calhoun	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
5	Duke Energy	Dale Goodwine	Negative	Third-Party Comments

1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Patrick Flaherty		Negative	Third-Party Comments
1	National Grid USA	Jacqueline Ryan		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
5	JEA	John Babik		Negative	Third-Party Comments
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A

3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Negative	Comments Submitted
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Negative	Comments Submitted
2	Independent Electricity System Operator	Pirouz Honarmand		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Negative	Third-Party Comments
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Ruida Shu		Abstain	N/A
6	Invenergy LLC	Colin Chilcoat		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Third-Party Comments

5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		None	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
3	TXNM Energy	Scott Thompson		Negative	Comments Submitted

3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
4	Seattle City Light	Robert Jones		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
					Third-

5	Xcel Energy, Inc.	Gerry Huitt		Negative	Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
6	Basin Electric Power Cooperative	Eve G Stromer		Negative	Third-Party Comments
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A
3	Seattle City Light	Zenon O'young-Chu		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted



Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 Implementation Plan IN 1 OT
Voting Start Date: 5/7/2025 12:01:00 AM
Voting End Date: 5/16/2025 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 242
Total Ballot Pool: 275
Quorum: 88
Quorum Established Date: 5/16/2025 2:27:28 PM
Weighted Segment Value: 39.46

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	73	1	20	0.328	41	0.672	0	5	7
Segment: 2	7	0.6	4	0.4	2	0.2	0	0	1
Segment: 3	64	1	23	0.426	31	0.574	0	3	7
Segment: 4	13	1	3	0.3	7	0.7	0	1	2
Segment: 5	67	1	19	0.358	34	0.642	0	4	10
Segment: 6	45	1	12	0.316	26	0.684	0	2	5
Segment: 7	0	0	0	0	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	0.3	2	0.2	1	0.1	0	2	1
Totals:	275	5.9	83	2.328	142	3.572	0	17	33

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Amanda Skubal		Negative	Comments Submitted
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
1	TXNM Energy	Lynn Goldstein		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	American Municipal Power	Amy Ritts		Negative	Third-Party Comments
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments

					Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	AEP	Jodi Yeary		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Sing Tay		Negative	Comments Submitted
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Black Hills Corporation	Josh Schumacher		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
1	Black Hills Corporation	Trevor Rombough		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party

					Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Negative	Comments Submitted
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	Third-Party Comments
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres		Negative	Third-Party Comments

1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
5	Leeward Renewable Energy	Rob Robertson		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	Salt River Project	Timothy Singh		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
3	Entergy	James Keele		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A

6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
3	Salt River Project	Mathew Weber		Negative	Comments Submitted
1	Salt River Project	Laura Somak		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Xcel Energy, Inc.	Nicholas Friebel	Joseph Gatten	None	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Negative	Comments Submitted
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments

5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	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
3	Eversource Energy	Vicki O'Leary		Negative	Third-Party Comments
5	Orsted Americas	Keith Smith		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Erin Doane		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	AEP	Randy Calhoun		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
					Third-

5	Duke Energy	Dale Goodwine		Negative	Party Comments
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Patrick Flaherty		Negative	Third-Party Comments
1	National Grid USA	Jacqueline Ryan		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
5	JEA	John Babik		Negative	Third-Party Comments
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A

3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Abstain	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Negative	Third-Party Comments
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Abstain	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
3	JEA	Marilyn Williams		Negative	Third-Party Comments
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A

3	Exelon	Kinte Whitehead		None	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A

6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Vijay Raghunathan		Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
6	Basin Electric Power Cooperative	Eve G Stromer		Negative	Third-Party Comments
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A

1	Northeast Missouri Electric Power Cooperative	Brett Douglas	Affirmative	N/A
6	Constellation	Kimberly Turco	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp	None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin	Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty	Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell	Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander	Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci	Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday	Negative	Comments Submitted



Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 | Non-binding Poll IN 1 NB
Voting Start Date: 5/7/2025 12:01:00 AM
Voting End Date: 5/16/2025 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 230
Total Ballot Pool: 260
Quorum: 88.46
Quorum Established Date: 5/16/2025 2:35:29 PM
Weighted Segment Value: 39.6

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	70	1	21	0.375	35	0.625	8	6
Segment: 2	6	0.3	0	0	3	0.3	2	1
Segment: 3	63	1	23	0.451	28	0.549	6	6
Segment: 4	13	1	5	0.5	5	0.5	1	2
Segment: 5	59	1	17	0.37	29	0.63	5	8
Segment: 6	43	1	12	0.353	22	0.647	3	6
Segment: 7	0	0	0	0	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	0.2	2	0.2	0	0	3	1
Totals:	260	5.5	80	2.248	122	3.252	28	30

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Negative	No Comment Submitted
1	Lower Colorado River Authority	Matt Lewis		Negative	No Comment Submitted
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Negative	No Comment Submitted
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Negative	No Comment Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	No Comment Submitted
4	Utility Services, Inc.	Carver Powers		Negative	No Comment Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	No Comment Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	American Municipal Power	Amy Ritts		Negative	Third-Party

					Comments
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	No Comment Submitted
3	Great River Energy	Michael Brytowski		Negative	No Comment Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	No Comment Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	No Comment Submitted
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Negative	No Comment Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	No Comment Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	No Comment Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	No Comment Submitted
3	AES - Indianapolis Power and Light Co.	Sing Tay		Negative	No Comment Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Negative	No Comment Submitted
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	No Comment Submitted
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	No Comment

4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	Submitted N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	No Comment Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	No Comment Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Negative	No Comment Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	No Comment Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	No Comment Submitted
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	No Comment Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	No Comment Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	No Comment Submitted
6	Tennessee Valley Authority	Jeffrey Powell		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	No Comment Submitted
6	Omaha Public Power District	Shonda McCain		Negative	No Comment Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
3	Omaha Public Power District	David Heins		Negative	No Comment Submitted
5	Invenergy LLC	Rhonda Jones		Negative	No Comment

					Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	No Comment Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	No Comment Submitted
6	Austin Energy	Imane Mrini		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
5	Leeward Renewable Energy	Rob Robertson		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	No Comment Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	No Comment Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	No Comment Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	No Comment Submitted
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	No Comment Submitted
6	Salt River Project	Timothy Singh		Negative	No Comment Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	No Comment Submitted
2	ISO New England, Inc.	John Pearson		Negative	No Comment Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	No Comment Submitted

1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	No Comment Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	No Comment Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	No Comment Submitted
3	Entergy	James Keele		Negative	No Comment Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	No Comment Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	Salt River Project	Mathew Weber		Negative	No Comment Submitted
1	Salt River Project	Laura Somak		Negative	No Comment Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Negative	No Comment Submitted
2	Midcontinent ISO, Inc.	Kirsten Rowley		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	AEP	Thomas Foltz		Negative	No Comment Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	No Comment Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	No Comment Submitted
5	Constellation	Alison MacKellar		Negative	No Comment Submitted
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	No Comment Submitted

5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Negative	No Comment Submitted
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	No Comment Submitted
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
6	Entergy	Julie Hall		Negative	No Comment Submitted
1	Platte River Power Authority	Marissa Archie		Negative	No Comment Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	No Comment Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	No Comment Submitted
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	No Comment Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	No Comment Submitted
3	Eversource Energy	Vicki O'Leary		Negative	No Comment Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	No Comment Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	No Comment Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	No Comment Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Negative	No Comment Submitted

5	Entergy - Entergy Services, Inc.	Gail Golden	Negative	No Comment Submitted
3	Con Ed - Consolidated Edison Co. of New York	Erin Doane	Negative	No Comment Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas	Negative	No Comment Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Abstain	N/A
6	Western Area Power Administration	Jennifer Neville	Negative	No Comment Submitted
5	Dairyland Power Cooperative	Tommy Drea	Negative	No Comment Submitted
6	AEP	Randy Calhoun	Negative	No Comment Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
5	Duke Energy	Dale Goodwine	Negative	No Comment Submitted
1	Exelon	Daniel Gacek	Negative	No Comment Submitted
1	Portland General Electric Co.	Brooke Jockin	Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons	Negative	No Comment Submitted
1	National Grid USA	Jacqueline Ryan	Negative	No Comment Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer	Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos	Negative	No Comment Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder	Negative	No Comment Submitted
6	Duke Energy	John Sturgeon	Negative	No Comment Submitted

3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	No Comment Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	No Comment Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	No Comment Submitted
1	Avista - Avista Corporation	Mike Magruder		Negative	No Comment Submitted
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	No Comment Submitted
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	No Comment Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	No Comment Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A

10	Northeast Power Coordinating Council	Ruida Shu		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	No Comment Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	No Comment Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	No Comment Submitted
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	No Comment Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		None	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	No Comment Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
5	Salt River Project	Matthew Jaramilla		Negative	No Comment Submitted
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A

1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Negative	No Comment Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	No Comment Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	No Comment Submitted
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	No Comment Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	No Comment Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	No Comment Submitted
5	Muscatine Power and Water	Chance Back		None	N/A
3	TXNM Energy	Scott Thompson		Negative	No Comment Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	No Comment Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	No Comment Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	No Comment Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	No Comment Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
			Hayden		No

3	Evergy	Marcus Moor	Maples	Negative	Comment Submitted
5	National Grid USA	Robin Berry		Negative	No Comment Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	No Comment Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	No Comment Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Negative	No Comment Submitted
1	Basin Electric Power Cooperative	David Rudolph		Negative	No Comment Submitted
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Negative	No Comment Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	No Comment Submitted
6	Lincoln Electric System	Eric Ruskamp		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	No Comment Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	No Comment Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	No Comment Submitted



Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 | Non-binding Poll IN 1 NB
Voting Start Date: 5/7/2025 12:01:00 AM
Voting End Date: 5/16/2025 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 228
Total Ballot Pool: 261
Quorum: 87.36
Quorum Established Date: 5/16/2025 2:34:30 PM
Weighted Segment Value: 49.74

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	26	0.491	27	0.509	10	8
Segment: 2	6	0.3	0	0	3	0.3	2	1
Segment: 3	63	1	26	0.52	24	0.48	7	6
Segment: 4	13	1	4	0.4	6	0.6	1	2
Segment: 5	59	1	22	0.524	20	0.476	8	9
Segment: 6	43	1	16	0.485	17	0.515	4	6
Segment: 7	0	0	0	0	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	0.2	2	0.2	0	0	3	1
Totals:	261	5.5	96	2.619	97	2.881	35	33

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Negative	No Comment Submitted
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	No Comment Submitted
4	Utility Services, Inc.	Carver Powers		Negative	No Comment Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	No Comment Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
3	Great River Energy	Michael Brytowski		Negative	No Comment Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	No Comment Submitted
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A

6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	No Comment Submitted
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	No Comment Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	No Comment Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	No Comment Submitted
3	AES - Indianapolis Power and Light Co.	Sing Tay		Negative	No Comment Submitted
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Negative	No Comment Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	No Comment Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	No Comment Submitted
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	No Comment Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	No Comment Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A
					No

4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comment Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	No Comment Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	No Comment Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	No Comment Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	No Comment Submitted
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Negative	No Comment Submitted
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	No Comment Submitted
6	Tennessee Valley Authority	Jeffrey Powell		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	No Comment Submitted
6	Omaha Public Power District	Shonda McCain		Negative	No Comment Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
3	Omaha Public Power District	David Heins		Negative	No Comment Submitted
5	Invenergy LLC	Rhonda Jones		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	No Comment Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	None	N/A
6	Imperial Irrigation District	Diana Torres		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	No Comment Submitted

6	Austin Energy	Imane Mrini		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
5	Leeward Renewable Energy	Rob Robertson		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	No Comment Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	No Comment Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	No Comment Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	No Comment Submitted
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	No Comment Submitted
6	Salt River Project	Timothy Singh		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	No Comment Submitted
2	ISO New England, Inc.	John Pearson		Negative	No Comment Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	No Comment Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	No Comment Submitted
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	No Comment Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	No Comment Submitted
3	Entergy	James Keele		Negative	No Comment

					Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	No Comment Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	Salt River Project	Mathew Weber		Affirmative	N/A
1	Salt River Project	Laura Somak		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	No Comment Submitted
2	Midcontinent ISO, Inc.	Kirsten Rowley		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	No Comment Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	No Comment Submitted
5	Constellation	Alison MacKellar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	No Comment Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	No Comment Submitted
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
6	Entergy	Julie Hall		Negative	No Comment Submitted
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	No Comment Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
					No

5	Ameren - Ameren Missouri	Sam Dwyer	Negative	Comment Submitted
6	Ameren - Ameren Services	Robert Quinlivan	Negative	No Comment Submitted
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano	Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu	Abstain	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson	Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden	Negative	No Comment Submitted
3	Eversource Energy	Vicki O'Leary	Negative	No Comment Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski	Negative	No Comment Submitted
5	Southern Company - Southern Company Generation	Leslie Burke	Negative	No Comment Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal	Negative	No Comment Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden	Negative	No Comment Submitted
3	Con Ed - Consolidated Edison Co. of New York	Erin Doane	Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads	Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas	Negative	No Comment Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco	Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert	Abstain	N/A
6	Western Area Power Administration	Jennifer Neville	Negative	No Comment Submitted
5	Dairyland Power Cooperative	Tommy Drea	Negative	No Comment Submitted
6	AEP	Randy Calhoun	Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	None	N/A
5	Duke Energy	Dale Goodwine	Negative	No Comment

					Submitted
1	Exelon	Daniel Gacek		Negative	No Comment Submitted
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	No Comment Submitted
1	National Grid USA	Jacqueline Ryan		Negative	No Comment Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	No Comment Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	No Comment Submitted
6	Duke Energy	John Sturgeon		Negative	No Comment Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	No Comment Submitted
1	Avista - Avista Corporation	Mike Magruder		Negative	No Comment Submitted
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A

5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	No Comment Submitted
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A
1	Seattle City Light	Michael Jang	Negative	No Comment Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Negative	No Comment Submitted
5	Edison International - Southern California Edison Company	Selene Willis	Negative	No Comment Submitted
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry	Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu	Abstain	N/A
1	Western Area Power Administration	Ben Hammer	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith	None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny	Negative	No Comment Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir	Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong	Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie	Affirmative	N/A
1	Duke Energy	Katherine Street	Negative	No Comment Submitted
3	JEA	Marilyn Williams	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell	Negative	No Comment Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier	Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans	None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
3	Exelon	Kinte Whitehead	None	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy	Affirmative	N/A
5	Lincoln Electric System	Brittany Millard	Abstain	N/A
1	Lincoln Electric System	Josh Johnson	None	N/A
3	Lincoln Electric System	Sam Christensen	Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins	Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Affirmative	N/A

1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	No Comment Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Negative	No Comment Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	No Comment Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	No Comment Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
3	TXNM Energy	Scott Thompson		Negative	No Comment Submitted
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	No Comment Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	No Comment Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A

1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	No Comment Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	No Comment Submitted
5	National Grid USA	Robin Berry		Negative	No Comment Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	No Comment Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	No Comment Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Negative	No Comment Submitted
1	Basin Electric Power Cooperative	David Rudolph		Negative	No Comment Submitted
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	No Comment Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	No Comment Submitted

1	Bonneville Power Administration	Kamala Rogers-Holliday	Negative	No Comment Submitted

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 | Non-binding Poll IN 1 NB
Voting Start Date: 5/7/2025 12:01:00 AM
Voting End Date: 5/16/2025 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 228
Total Ballot Pool: 260
Quorum: 87.69
Quorum Established Date: 5/16/2025 2:27:01 PM
Weighted Segment Value: 41.75

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	22	0.407	32	0.593	9	8
Segment: 2	6	0.3	0	0	3	0.3	2	1
Segment: 3	62	1	23	0.46	27	0.54	7	5
Segment: 4	13	1	3	0.3	7	0.7	1	2
Segment: 5	59	1	19	0.452	23	0.548	8	9
Segment: 6	43	1	12	0.364	21	0.636	4	6
Segment: 7	0	0	0	0	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	0.2	2	0.2	0	0	3	1
Totals:	260	5.5	81	2.183	113	3.317	34	32

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Negative	No Comment Submitted
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		None	N/A
5	Imperial Irrigation District	Tino Zaragoza		Negative	Third-Party Comments
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	No Comment Submitted
4	Utility Services, Inc.	Carver Powers		Negative	No Comment Submitted
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	No Comment Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
3	Great River Energy	Michael Brytowski		Negative	No Comment Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	No Comment Submitted

3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	No Comment Submitted
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	No Comment Submitted
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	No Comment Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	No Comment Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	No Comment Submitted
3	AES - Indianapolis Power and Light Co.	Sing Tay		Negative	No Comment Submitted
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Negative	No Comment Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	No Comment Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	No Comment Submitted
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	No Comment Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	No Comment Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	No Comment

					Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	No Comment Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	No Comment Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	No Comment Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	No Comment Submitted
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	No Comment Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	No Comment Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	No Comment Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Negative	No Comment Submitted
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	No Comment Submitted
6	Tennessee Valley Authority	Jeffrey Powell		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	No Comment Submitted
6	Omaha Public Power District	Shonda McCain		Negative	No Comment Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		None	N/A
3	Omaha Public Power District	David Heins		Negative	No Comment Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	No Comment Submitted
5	Invenergy LLC	Rhonda Jones		None	N/A

3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	No Comment Submitted
6	Imperial Irrigation District	Diana Torres		Negative	Third-Party Comments
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Negative	No Comment Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	No Comment Submitted
6	Austin Energy	Imane Mrini		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
5	Leeward Renewable Energy	Rob Robertson		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	No Comment Submitted
5	U.S. Bureau of Reclamation	Wendy Kalidass		Negative	No Comment Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	No Comment Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	No Comment Submitted
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	No Comment Submitted
6	Salt River Project	Timothy Singh		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	No Comment Submitted
2	ISO New England, Inc.	John Pearson		Negative	No Comment Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	No Comment Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	No Comment Submitted

5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	No Comment Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	No Comment Submitted
3	Entergy	James Keele		Negative	No Comment Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	No Comment Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
3	Salt River Project	Mathew Weber		Affirmative	N/A
1	Salt River Project	Laura Somak		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	No Comment Submitted
2	Midcontinent ISO, Inc.	Kirsten Rowley		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	No Comment Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	No Comment Submitted
5	Constellation	Alison MacKellar		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	No Comment Submitted
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	No Comment Submitted

5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
6	Entergy	Julie Hall		Negative	No Comment Submitted
1	Platte River Power Authority	Marissa Archie		Negative	No Comment Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	No Comment Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	No Comment Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	No Comment Submitted
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	No Comment Submitted
3	Eversource Energy	Vicki O'Leary		Negative	No Comment Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	No Comment Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	No Comment Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Negative	No Comment Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	No Comment Submitted
3	Con Ed - Consolidated Edison Co. of New York	Erin Doane		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	No Comment Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A

3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	No Comment Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	No Comment Submitted
6	AEP	Randy Calhoun		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Negative	No Comment Submitted
1	Exelon	Daniel Gacek		Negative	No Comment Submitted
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	No Comment Submitted
1	National Grid USA	Jacqueline Ryan		Negative	No Comment Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Negative	No Comment Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	No Comment Submitted
6	Duke Energy	John Sturgeon		Negative	No Comment Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
1	JEA	Joseph McClung		Negative	No Comment Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-	Negative	No Comment

		Marquis		Submitted
1	Avista - Avista Corporation	Mike Magruder	Negative	No Comment Submitted
5	JEA	John Babik	Negative	No Comment Submitted
1	Pedernales Electric Cooperative, Inc.	Bradley Collard	None	N/A
1	New York Power Authority	Daniel Valle	Affirmative	N/A
3	New York Power Authority	Richard Machado	Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry	Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller	Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove	Affirmative	N/A
6	New York Power Authority	Shelly Dineen	Affirmative	N/A
5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Negative	No Comment Submitted
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A
1	Seattle City Light	Michael Jang	Negative	No Comment Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Negative	No Comment Submitted
5	Edison International - Southern California Edison Company	Selene Willis	Negative	No Comment Submitted
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry	Negative	No Comment Submitted
10	Northeast Power Coordinating Council	Ruida Shu	Abstain	N/A
1	Western Area Power Administration	Ben Hammer	Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith	None	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny	Negative	No Comment Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir	Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong	Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott	Affirmative	N/A
1	Duke Energy	Katherine Street	Negative	No Comment

					Submitted
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Negative	No Comment Submitted
3	JEA	Marilyn Williams		Negative	No Comment Submitted
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	No Comment Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		None	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	No Comment Submitted
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Negative	No Comment Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	No Comment Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A

5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Negative	No Comment Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	No Comment Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	No Comment Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	No Comment Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Negative	No Comment Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	No Comment Submitted
5	National Grid USA	Robin Berry		Negative	No Comment Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Negative	No Comment Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	No Comment Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	No Comment Submitted

5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	No Comment Submitted
6	Basin Electric Power Cooperative	Eve G Stromer		Negative	No Comment Submitted
1	Basin Electric Power Cooperative	David Rudolph		Negative	No Comment Submitted
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Kimberly Turco		Abstain	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	No Comment Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	No Comment Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	No Comment Submitted



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

MOD-032-2 is posted for a 34-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
(The above was Posted under IRPTF SAR pre–Order No. 901)	
30-day formal comment period with initial ballot	April 17 – May 16, 2025

Anticipated Actions	Date
34-day formal comment period with ballot	August 8 –September 10, 2025
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

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):

Distributed Energy Resource (DER): A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** Data for Power System Modeling and Analysis

2. **Number:** MOD-032-2

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Generator Owner

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation.

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data, that is responsive to the technical concern.

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

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

   - Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. **Compliance Monitoring and Enforcement Program:** Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

3. **Potential Noncompliance (PNC) Abeyance Period:**
For a period of two years following the compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2, Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. "Good faith" in this context refers

to a sincere intention to comply with Reliability Standard MOD-032-2 regarding the provision of aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes in accordance with the data requirements and reporting procedures for the Planning Coordinator's planning area developed under Requirement R1, subject to the estimation requirements of Requirement R2, Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.
R2.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not

	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

	Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission

	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data

	in the format specified by the ERO or its designee.	the format specified by the ERO or its designee.	required data in the format specified by the ERO or its designee.	in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List
- MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO).

MOD-032-2 – ATTACHMENT 1
Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in Interconnection-wide cases. The joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify entity responsibility and data flow processes. The typical functional entity[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be identified by the bus number, name, and/or identifier that is assigned in conjunction with the Planning Coordinator, Transmission Owner, or Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
1. Each bus [TO] a. Nominal voltage b. Area, zone and owner 2. Aggregate Demand[3] [DP] a. Real and reactive power* b. In-service status* 3. Generating and storage units[4] [GO, TO[5], RP (for future planned resources only)] a. Real power capabilities - gross maximum and minimum values b. Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. Regulated bus* and voltage set point* (as typically provided by the TOP) e. Machine MVA base	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[3] [DP] 6. Wind plant model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control 8. Static Var Systems and FACTS [GO, TO, DP] 9. DC System Models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive sequence data b. Negative sequence data c. Zero sequence data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
f. Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. Generator type (hydro, wind, fossil, solar, nuclear, etc.) h. In-service status* 4. AC Transmission Line or Circuit [TO] a. Impedance parameters (positive sequence) b. Susceptance (line charging) c. Ratings (normal and emergency)* d. In-service status* 5. DC Transmission Systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. Nominal voltages of windings b. Impedance(s) c. Tap ratios (voltage or phase angle)* d. Minimum and maximum tap position limits e. Number of tap positions (for both the ULTC and NLTC) f. Regulated bus (for voltage regulating transformers)* g. Ratings (normal and emergency)* h. In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. Admittances (MVars) of each capacitor and reactor b. Regulated voltage band limits* (if mode of operation not fixed) c. Mode of operation (fixed, discrete, continuous, etc.) d. Regulated bus* (if mode of operation not fixed) e. In-service status* 8. Static Var Systems [TO] a. Reactive limits b. Voltage set point* c. Fixed/switched shunt, if applicable d. In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1)	a. parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
b. Real power capability c. DER type (solar, battery, diesel generator, etc.) 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This attachment describes the process by which changes may be made to the Unacceptable Models List.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
    a. The model name;
    b. Alternative model name(s), if any;
    c. Organization(s) the submitting entity represents;
    d. Description of the model's stated intent;
    e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
    f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
    g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
    h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.
5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving

the change request, the NERC RSTC shall also recommend an effective date for the change.

6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

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

MOD-032-2 is posted for a 34-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
(The above was Posted under IRPTF SAR pre–Order No. 901)	
30-day formal comment period with initial ballot	April 17 – May 16, 2025

Anticipated Actions	Date
34-day formal comment period with ballot	August 8 –September 10, 2025
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

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):

Distributed Energy Resource~~s~~ (DER): A ~~G~~generator~~s and~~or energy storage technology~~ies~~ connected to a distribution system that ~~are~~is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including ~~those~~one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   ~~1.1.~~4.1. **Functional Entities:**

   - ~~1.1.1~~4.1.1 Balancing Authority
   - ~~1.1.2~~4.1.2 Distribution Provider
   - ~~1.1.3~~4.1.3 Generator Owner
   - ~~1.1.4~~4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)
   - ~~1.1.5~~4.1.5 Resource Planner
   - ~~1.1.6~~4.1.6 Transmission Owner
   - ~~1.1.7~~4.1.7 Transmission Planner
   - ~~1.1.8~~4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible ~~entity~~ for each required item.

~~**1.2.** Requirements for model submissions in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization (ERO).~~

~~**1.3.**~~**1.2.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

~~**1.3.1.**~~**1.2.1.** Data format;

~~**1.3.2.**~~**1.2.2.** Level of detail to which equipment shall be modeled;

~~**1.3.3.**~~**1.2.3.** Case types or scenarios to be modeled; and

~~**1.3.4.**~~**1.2.4.** A schedule for submission of data at least once every 13 calendar months.

~~**1.4.**~~**1.3.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If ~~the responsible~~a functional entity~~, as identified in Requirement R1 Part 1.1,~~ is required to provide data for one or more of the following and is unable to gather ~~unregistered Inverter-based Resource (IBR)[1] data or aggregate Distributed~~such data ~~and parameters and include~~, the functional entity shall provide an ~~explanation of the limitations~~estimate of the ~~availability of~~ data, an explanation of the limitations of ~~any~~the estimated data ~~provided~~, and the method used for estimation.

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each ~~registered~~functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying

[1] ~~As used in this standard, the phrase "unregistered IBR" refers to a Bulk-Power System connected IBR that does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.~~

Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data~~;~~, that is responsive to the technical concern.

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each ~~registered~~ functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

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

   - Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. **Compliance Monitoring and Enforcement Program:** Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

3. **Potential Noncompliance (PNC) Abeyance Period:**
   For a period of two years following the compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in

accordance with the relevant implementation plan. “Good faith” in this context refers to a sincere intention to comply with Reliability Standard MOD-032-2 regarding the provision of aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes in accordance with the data requirements and reporting procedures for the Planning Coordinator’s planning area developed under Requirement R1, subject to the estimation requirements of Requirement R2 Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.
R2.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not

	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

	Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission

	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data

	in the format specified by the ERO or its designee.	the format specified by the ERO or its designee.	required data in the format specified by the ERO or its designee.	in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List
- MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO).

MOD-032-2 – ATTACHMENT 1
Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in Interconnection-wide cases. ~~A Planning Coordinator may specify additional information that includes specific information required for each item in the table below.~~ The joint Planning Coordinator ~~may~~/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify ~~additional information that includes specific information required for each item in the table below. Each~~entity responsibility and data flow processes. The typical functional entity[2] ~~typically~~ responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. ~~The joint Planning Coordinator /Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify the functional entity responsibility and data flow processes.~~ The data reported shall be identified by the bus number, name, and/or identifier that is assigned in conjunction with the Planning Coordinator, Transmission Owner, or Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
1. Each bus [TO] a. ~~n~~Nominal voltage b. ~~a~~Area, zone and owner 2. Aggregate Demand[3] [DP] a. ~~r~~Real and reactive power* b. ~~i~~In-service status* 3. Generating and storage units[4] [GO, TO[5], RP (for future planned resources only)] a. ~~r~~Real power capabilities - gross maximum and minimum values b. ~~r~~Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. ~~s~~Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above).	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[3] [DP] 6. Wind plant model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]] a. ~~IBR~~Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive ~~S~~sequence ~~D~~data b. Negative ~~S~~sequence ~~D~~data c. Zero ~~S~~sequence ~~D~~data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics	short circuit
d. ~~r~~Regulated bus* and voltage set point* (as typically provided by the TOP) e. ~~m~~Machine MVA base f. ~~g~~Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. ~~g~~Generator type (hydro, wind, fossil, solar, nuclear, etc.) h. ~~i~~In-service status* 4. AC Transmission Line or Circuit [TO] a. ~~i~~Impedance parameters (positive sequence) b. ~~s~~Susceptance (line charging) c. ~~r~~Ratings (normal and emergency)* d. ~~i~~In-service status* 5. DC Transmission ~~s~~Systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. ~~n~~Nominal voltages of windings b. ~~i~~Impedance(s) c. ~~t~~Tap ratios (voltage or phase angle)* d. ~~m~~Minimum and maximum tap position limits e. ~~n~~Number of tap positions (for both the ULTC and NLTC) f. ~~r~~Regulated bus (for voltage regulating transformers)* g. ~~r~~Ratings (normal and emergency)* h. ~~i~~In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. ~~a~~Admittances (MVars) of each capacitor and reactor b. ~~r~~Regulated voltage band limits* (if mode of operation not fixed) c. ~~m~~Mode of operation (fixed, discrete, continuous, etc.) d. ~~r~~Regulated bus* (if mode of operation not fixed) e. ~~i~~In-service status* 8. Static Var Systems [TO] a. ~~r~~Reactive limits b. ~~v~~Voltage set point*	8. Static Var Systems and FACTS [GO, TO, DP] 9. DC ~~s~~System ~~m~~Models [TO] 10. Aggregate Distributed Energy Resource (DER) ~~data~~data[7] [DP, TO][6] a. ~~DER~~Pparameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those ~~capabilities~~items for modeling purposes. b. ~~i~~Indication whether DERs are ~~is~~ subject to tripping in conjunction with UFLS or UVLS. 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics	short circuit
c. ~~f~~Fixed/switched shunt, if applicable d. ~~i~~In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.) 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. ~~This includes IBR,~~ Generating and storage units include IBRs and synchronous condensers~~, and pumped storage~~.
5. The Transmission Owner is the typical entity responsible ~~entity~~ for collecting and providing data for ~~unregistered IBRs~~an IBR that ~~are~~is not ~~DERs~~a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This attachment describes the process by which changes may be made to the Unacceptable Models List.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
    a. The model name;
    b. Alternative model name(s), if any;
    c. Organization(s) the submitting entity represents;
    d. Description of the model's stated intent;
    e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
    f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
    g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
    h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.

5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving the change request, the NERC RSTC shall also recommend an effective date for the change.
6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

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

MOD-032-2 is posted for a 34-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025

Anticipated Actions	Date
34-day formal comment period with ballot	August 8 –September 10, 2025
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

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):

Distributed Energy Resource (DER): A generators or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   ~~1.1.~~**4.1.** **Functional Entities:**

   ~~1.1.1~~**4.1.1** Balancing Authority

   4.1.2 Distribution Provider

   ~~1.1.2~~**4.1.3** Generator Owner

   ~~**1.1.3** Load Serving Entity~~

   ~~1.1.4~~**4.1.4** Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.~~

   ~~1.1.5~~**4.1.5** Resource Planner

   ~~1.1.6~~**4.1.6** Transmission Owner

   ~~1.1.7~~**4.1.7** Transmission Planner

   ~~1.1.8~~**4.1.8** Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

   ~~MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is~~

approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation.

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each ~~registered~~functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~2.1.~~3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data~~;~~, that is responsive to the technical concern.

~~3.1.~~3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each ~~registered~~functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

The applicable entity shall keep data or evidence to show compliance ~~with~~ 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.

- Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. Compliance Monitoring and ~~Assessment Processes~~ Enforcement Program:
Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for ~~a list of~~performing compliance monitoring and ~~assessment processes~~enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

~~**1.3. Additional Compliance Information**~~

~~None~~

3. Potential Noncompliance (PNC) Abeyance Period:
For a period of two years following the compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for

an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. “Good faith” in this context refers to a sincere intention to comply with Reliability Standard MOD-032-2 regarding the provision of aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes in accordance with the data requirements and reporting procedures for the Planning Coordinator’s planning area developed under Requirement R1, subject to the estimation requirements of Requirement R2 Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

~~Table of Compliance Elements~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R2.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;

	the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, ~~Load Serving Entity,~~ Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its

				Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

	within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

- ~~None.~~Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List
- MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO).

MOD-032-2 – ATTACHMENT 1~~:~~

Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in ~~*the*~~ Interconnection-wide cases. ~~*A*~~The joint Planning Coordinator ~~*may*~~/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify ~~*additional information that includes specific information required for each item in the table below. Each*~~entity responsibility and data flow processes. The typical functional *entity*~~[1]~~[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be ~~*as*~~ identified by the bus number, name, and/or identifier that is assigned in conjunction with the ~~*PC, TO*~~Planning Coordinator, Transmission Owner, or ~~*TP.*~~ Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	**short circuit**
1. Each bus [TO] a. ~~n~~Nominal voltage b. ~~a~~Area, zone and owner 2. Aggregate Demand~~[3]~~[2] [~~LSE~~DP] a. ~~r~~Real and reactive power* b. ~~i~~In-service status*	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System ~~S~~stabilizer [GO, RP(for future planned resources only)]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO]

~~[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).~~

~~[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
3. Generating and storage Units[4] ~~3~~ [GO, TO[5], RP (for future planned resources only)] a. ~~r~~Real power capabilities - gross maximum and minimum values b. ~~r~~Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. ~~s~~Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. ~~r~~Regulated bus* and voltage set point* (as typically provided by the TOP) e. ~~m~~Machine MVA base f. ~~g~~Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. ~~g~~Generator type (hydro, wind, fossil, solar, nuclear, etc) h. ~~i~~In-service status* 4. AC Transmission Line or Circuit [TO] a. ~~i~~Impedance parameters (positive sequence) b. ~~s~~Susceptance (line charging) c. ~~r~~Ratings (normal and emergency)* d. ~~i~~In-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. ~~n~~Nominal voltages of windings	5. Aggregated Demand[3] [~~LSE~~DP] 6. Wind ~~T~~turbine ~~Data~~model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]]~~Photovoltaic systems [GO]~~ ~~7.~~a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control. 8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC ~~s~~System models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

~~[3] Including synchronous condensers and pumped storage.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
b. ~~i~~Impedance(s) c. ~~t~~Tap ratios (voltage or phase angle)* d. ~~m~~Minimum and maximum tap position limits e. ~~n~~Number of tap positions (for both the ULTC and NLTC) f. ~~r~~Regulated bus (for voltage regulating transformers)* g. ~~r~~Ratings (normal and emergency)* h. ~~i~~In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. ~~a~~Admittances (MVars) of each capacitor and reactor b. ~~r~~Regulated voltage band limits* (if mode of operation not fixed) c. ~~m~~Mode of operation (fixed, discrete, continuous, etc.) d. ~~r~~Regulated bus* (if mode of operation not fixed) e. ~~i~~In-service status* 8. Static Var Systems [TO] a. ~~r~~Reactive limits b. ~~v~~Voltage set point* c. ~~f~~Fixed/switched shunt, if applicable d. ~~i~~In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.)		

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]		

~~Guidelines and Technical Basis~~

~~For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.~~

~~The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.~~

~~An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.~~

~~The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and~~

~~to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).~~

~~The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).~~

~~Rationale:~~

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

~~Rationale for R1:~~

~~This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short-circuit data also required to perform short-circuit studies. The addition of short-circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.~~

~~In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.~~

~~This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.~~

~~This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:~~

~~Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:~~

~~1) reduce the quantity of MOD standards;~~
~~2) add short circuit data as a requirement to the MOD standards; and~~
~~3) supply data and models:~~
~~a. add requirement identifying who provides and who receives data;~~
~~b. identify acceptability;~~
~~c. standard format;~~
~~d. how to deal with new technologies (user written models if no standard model exists); and~~
~~e. shareability.~~

~~4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.~~

~~5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.~~

~~6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.~~

~~Rationale for R2:~~

~~This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."~~

~~Rationale for R3:~~

~~In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.~~

~~This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.~~

~~Rationale for R4:~~

~~This requirement will replace MOD-014 and MOD-015.~~

~~This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.~~

~~The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).~~

~~This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).~~

~~For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.~~

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs, and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This attachment describes the process by which changes may be made to the Unacceptable Models List.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
    a. The model name;
    b. Alternative model name(s), if any;
    c. Organization(s) the submitting entity represents;
    d. Description of the model's stated intent;
    e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
    f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
    g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
    h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.

5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving the change request, the NERC RSTC shall also recommend an effective date for the change.
6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard for a formal 34-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
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Anticipated Actions	Date
25-day formal comment period with ballot	August 8 –September 10, 2025
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection
2. **Number:** IRO-010-6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Transmission Operator
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for model submissions to be consistent with the model submitted for planning purposes, as applicable;

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2 and Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R1	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
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2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	
6	TBD	Adopted by NERC Board of Trustees	FERC Order 901 Modifications

Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard for a formal 34-day comment period.

Completed Actions	Date
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25-day formal comment period with ballot	August 8 –September 10, 2025
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A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection
2. **Number:** IRO-010-6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Transmission Operator
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-02

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for model submissions to be consistent with the model submitted for planning purposes~~in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization~~, as applicable;

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, ~~Reliability Coordinator,~~ Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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:

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1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
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R1	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
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R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

Version History

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5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	

6	TBD	Adopted by ~~the~~ NERC Board of Trustees	~~Revisions to address~~ FERC Order ~~No.~~ 901 ~~directives.~~ Modifications

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1. **Title:** Reliability Coordinator Data and information Specification and Collection

2. **Number:** IRO-010-~~5~~6

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4. **Applicability:**

   4.1. Reliability Coordinator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Transmission Operator

   4.6. Transmission Owner

   4.7. Distribution Provider

5. **Effective Date:** See Implementation Plan for Project ~~2021-06.~~2022-02.

B. Requirements

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~~**1.5.3**~~**1.5.4** Provisions to update or correct data and information, as applicable or necessary~~.~~;

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M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, ~~Reliability Coordinator,~~ Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

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 the ~~mandatory and enforceable~~NERC 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~~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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2~~,~~ and Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
~~As defined in the NERC Rules of Procedure,~~ "Compliance Monitoring and Enforcement Program" ~~refers~~or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the ~~identification~~NERC Rules of Procedure) or the Commission-approved program of ~~the processes~~a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that ~~will be used to evaluate data or~~

~~information~~is responsible for ~~the purpose of assessing performance or outcomes~~performing compliance monitoring and enforcement activities with ~~the associated reliability standard~~respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R1.	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the ~~SDT~~DT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specification.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

- Project 2022-02 Implementation Plan
- Project 2022-002 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO- 010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	

6	TBD	Adopted by NERC Board of Trustees	FERC Order 901 Modifications

Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard for a formal 34-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025

Anticipated Actions	Date
34-day formal comment period with ballot	August 8 –September 10, 2025
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for model submissions to be consistent with the model submitted for planning purposes, as applicable;

1.5.4. Provisions to update or correct data and information, as applicable or necessary;

1.5.5. A mutually agreeable format;

1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and

information, as applicable;

2.5.3. Requirements for model submissions to be consistent with the model submitted for planning purposes, as applicable;

2.5.4. Provisions to update or correct data and information, as applicable or necessary.

2.5.5. A mutually agreeable format.

2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations

of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (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 Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of

the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1, Part1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, Board Of Trustees approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5. Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1. Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7. Docket	

		No.RD25-5-000	
8	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives

Standard Development Timeline

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Description of Current Draft

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Anticipated Actions	Date
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5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for model submissions ~~in accordance~~to be consistent with the ~~Criteria~~model submitted for ~~Acceptable Models maintained by the Electric Reliability Organization~~ planning purposes, as applicable;

1.5.4. Provisions to update or correct data and information, as applicable or necessary;

1.5.5. A mutually agreeable format;

1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Requirements for model submissions ~~in accordance~~to be consistent with the ~~Criteria~~model submitted for ~~Acceptable Models maintained by the ERO~~planning purposes, as applicable;

2.5.4. Provisions to update or correct data and information, as applicable or necessary.

2.5.5. A mutually agreeable format.

2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to,

electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (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 Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of

the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the ~~Drafting Team (DT)~~ drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1, Part1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, ~~BOT~~Board Of Trustees approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5. Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1. Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7. Docket	

		No.RD25-5-000	
8	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives

Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard for a formal 34-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025

Anticipated Actions	Date
34-day formal comment period with ballot	August 8 –September 10, 2025
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-~~7~~8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-~~03~~02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following~~.~~:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for model submissions to be consistent with the model submitted for planning purposes, as applicable;

~~**1.5.3.**~~**1.5.4.** Provisions to update or correct data and information, as applicable or necessary;

~~**1.5.4.**~~**1.5.5.** A mutually agreeable format;

~~1.5.5.~~1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following~~.~~:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Requirements for model submissions to be consistent with the model

submitted for planning purposes, as applicable;

~~2.5.3.~~2.5.4. Provisions to update or correct data and information, as applicable or necessary.

~~2.5.4.~~2.5.5. A mutually agreeable format.

~~2.5.5.~~2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or ~~e-mail~~email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or ~~e-mail~~email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence

for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the ~~Standard~~ Drafting Team (~~SDT~~DT) is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
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3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7 Docket No.RD25-5-000	

~~7~~8	TBD	~~Energy Assurance Modifications – Addition of Near-Term ERA.~~Adopted by the NERC Board of Trustees	~~Revised~~Revisions to address FERC Order No. 901 directives

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Implementation Plan

Project 2022-02 Uniform Modeling Framework for IBR

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-6 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-8 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-5 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard(s)

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

- None

Applicable Entities

- See subject standards

Glossary of Terms used in NERC Reliability Standards

This section includes a newly defined term used in the NERC Reliability Standards. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, the defined term will be removed from the individual standard and added to the NERC Glossary.

Proposed New Definition:

Distributed Energy Resource (DER):

A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

Background

As the penetration of DERs continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk-Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BPS. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DERs for planning studies (including both utility-scale and retail-scale DERs) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DERs.

Further, in Order No. 901,[1] the U.S. Federal Energy Regulatory Commission ("FERC") found that it is imperative for NERC to develop new or modified Reliability Standards to address reliability concerns "related to IBRs at all stages of interconnection, planning, and operations."[2]. Among other things, FERC directed NERC to develop requirements addressing the provision of IBR and DER data to the entities responsible for the planning and operation of the BPS. Detailed information on the specific FERC Order No. 901 directives addressed through this project is available in Project 2022-02 Consideration of Order No. 901 Directives.

Proposed Reliability Standard MOD-032-2 replaces Load-Serving Entity with Distribution Provider as an applicable entity. Data items specific to IBRs and DERs were added to Attachment 1: Data Reporting Requirements, consistent with addressing the FERC Order No. 901 directives. Proposed Reliability Standard MOD-032-2 also adds a new Part 1.4 in Requirement R1, which would require the Planning Coordinator and Transmission Planner to specify submission of standard library dynamic models, user-defined models or both. Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. New Requirement R1, Part 1.4.2 is responsive to FERC concerns about model usability and non-convergence by requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions. New Requirement R2, Part 2.1 addresses estimation of unregistered IBR or DER data where actual data is not available, consistent with the directives in Order No. 901. New Requirement R2, Part 2.2 addresses the provision of dynamic models accepted under the MOD-026 standard, and new Requirement R2, Part 2.3 requires any entity submitting a model included on the Unacceptable Model List maintained by the ERO to include a technical rationale with its submission supporting the use of the model. Altogether, these modifications establish a uniform modeling framework that incorporates both IBR and DER data and facilitates model accuracy in alignment with FERC Order No. 901.

[1] Reliability Standards to Address Inverter-Based Resources, Order No. 901, 185 FERC ¶ 61,042 (2023).
[2] Id. at P 25

Revisions in the Reliability Standards TOP-003-8 and IRO-010-6 data specification standards specify that entities responsible for developing and distributing data specifications shall include requirements for model submissions consistent with the model submitted for planning purposes, as applicable.

General Considerations

In developing this implementation plan, the drafting team (DT) considered the time that would be necessary to update modeling data requirements and reporting procedures for MOD-032-2, including identifying the proper reporting entity for modeling data related to IBRs (including IBRs that are not DERs and do not meet the criteria that would require the owner(s) to register with NERC for mandatory Reliability Standards compliance purposes) and aggregate DERs. The DT also considered that the standard would become applicable to the Distribution Provider (DP) for the first time. During the 24 months prior to the effective date of Requirement R1, the applicable entities would be expected to participate in PC/TP processes to change the modeling data reporting requirements related to IBRs and aggregate DERs and should be able to start working on data collection processes and methods. The applicable entities in Requirement R2 would then have an additional 12 months to complete and implement data collection prior to the compliance dates of Requirements R2, R3, and R4. This timeline also allows for the development of new data estimation processes developed under MOD-032-2 Requirement R2, Part 2.1 and for the development of technical rationale to support the use of models included on the Unacceptable Model List maintained by the ERO, where applicable. Requirements adjusted in Reliability Standards IRO-010-6 and TOP-003-8 may not be practical to implement prior to full implementation of MOD-032-2, and therefore were set to the same implementation timeline. One additional limitation the DT considered is the requirement for all FERC Order No. 901 directives to be fully implemented by January 1, 2030, including those to be addressed by future standard revisions that may be dependent upon the implementation of these standard revisions.

In summary, this implementation plan would provide a full 36 months for MOD-032 Requirements R2, R3, R4, IRO-010, and TOP-003 from FERC approval until data is required to be reported under the revised requirements. During the phased-in compliance period for Requirements R2-R4, entities shall continue to provide data and perform other required actions in accordance with specifications developed under Reliability Standard MOD-032-1, unless entities are able to comply with the revised requirements sooner.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource is provided below. Where the DT 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 MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator and Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

During the phased-in compliance period, entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 unless they are compliant with revised Planning Coordinator/Transmission Planner data requirements and reporting procedures under Reliability Standard MOD-032-2 Requirement R1.

Definition – Distributed Energy Resource (DER)

Where approval by an applicable governmental authority is required, the definition of Distributed Energy Resource (DER) shall become effective on the first day of the first calendar quarter that is after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard IRO-010-6

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard TOP-003-8

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1

Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard IRO-010-5

Reliability Standard IRO-010-5 shall be retired immediately prior to the effective date of Reliability Standard IRO-010-6 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard TOP-003-7

Reliability Standard TOP-003-7 shall be retired immediately prior to the effective date of Reliability Standard TOP-003-8 in the particular jurisdiction in which the revised standard is becoming effective.

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Implementation Plan

Project 2022-02 Uniform Modeling Framework for IBR

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-6 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-8 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-5 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard(s)

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

- None

Applicable Entities

- ~~Reliability Coordinator~~
- ~~Balancing Authority~~
- ~~Distribution Provider~~
- ~~Generator Owner~~
- ~~Generator Operator~~
- ~~Planning Coordinator~~
- ~~Resource Planner~~
- ~~Transmission Owner~~
- ~~Transmission Operator~~
- ~~Transmission Planner~~
- ~~Transmission Service Provider~~

- ~~NERC~~ See subject standards

Glossary of Terms used in NERC Reliability Standards

This section includes a newly defined term used in the NERC Reliability Standards. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, the defined term will be removed from the individual standard and added to the NERC Glossary ~~of Terms~~.

Proposed New Definition:
Distributed Energy Resource (DER):
A ~~G~~generators ~~and~~ or energy storage technology~~ies~~ connected to a distribution system that ~~are~~is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including ~~those~~one connected behind the meter of an end-use customer that is supplied from a distribution system.

Background

As the penetration of DERs continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk-Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the ~~Bulk Electric System.~~BPS. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DERs for planning studies (including both utility-scale and retail-scale DERs) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DERs.

Further, in Order No. 901,[1] the U.S. Federal Energy Regulatory Commission ("FERC") found that it is imperative for NERC to develop new or modified Reliability Standards ~~MOD-032, IRO-010, and TOP-003~~ to address reliability concerns "related to IBRs at all stages of interconnection, planning, and operations."[2]. Among other things, FERC directed NERC to develop requirements addressing the provision of IBR and DER data to the entities responsible for the planning and operation of the BPS. Detailed information on the specific FERC Order No. 901 directives addressed through this project is available in Project 2022-02 Consideration of Order No. 901 Directives.

Proposed Reliability Standard MOD-032-2 replaces ~~the~~ Load-Serving Entity ~~as an applicable entity~~ with ~~the~~ Distribution Provider ~~and updates~~as an applicable entity. Data items specific to IBRs and DERs were added to Attachment 1: Data Reporting Requirements ~~with data specific to DERs and IBRs~~, consistent with addressing the FERC Order No. 901 directives. Proposed Reliability Standard MOD-032-2 also adds a new Part 1.~~2~~4 in Requirement R1, which would require the Planning Coordinator and Transmission Planner to ~~include in their data requirements~~specify submission of standard library dynamic models, user-defined models or both. Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and

[1] Reliability Standards to Address Inverter-Based Resources, Order No. 901, 185 FERC ¶ 61,042 (2023).
[2] Id. at P 25

~~procedures~~allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. New Requirement R1, Part 1.4.2 is responsive to FERC concerns about model ~~submissions in accordance with the Criteria for Acceptable Models maintained~~usability and non-convergence by ~~the Electric Reliability Organization (ERO).~~requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions. New Requirement R2, Part 2.1 addresses estimation of unregistered IBR or DER data where actual data is not available, consistent with the directives in Order No. 901. New Requirement R2, Part 2.2 addresses the provision of dynamic models accepted under the MOD-026 standard, and new Requirement R2, Part 2.3 requires any entity submitting a model included on the Unacceptable Model List maintained by the ERO to include a technical rationale with its submission supporting the use of the model. Altogether, these modifications establish a uniform modeling framework that incorporates both IBR and DER data and facilitates model accuracy in alignment with FERC Order No. 901.

Revisions in the Reliability Standards TOP-003-8 and IRO-010-6 data specification standards specify that entities responsible for developing and distributing data specifications shall include requirements for model submissions ~~in accordance~~consistent with the ~~Criteria~~model submitted for ~~Acceptable Models List maintained by the ERO~~planning purposes, as applicable.

General Considerations

In developing this implementation plan, the drafting team (DT) considered the time ~~in MOD-032-2~~ that would be necessary to ~~develop~~update modeling data requirements and reporting procedures for MOD-032-2, including identifying the proper reporting entity~~,~~ for modeling data related to IBRs~~,~~ (including ~~unregistered~~ IBRs that are not DERs and do not meet the criteria that would require the owner(s) to register with NERC for mandatory Reliability Standards compliance purposes) and aggregate DERs. The DT also considered that the standard would become applicable to the Distribution Provider (DP) for the first time. ~~Transmission Owners (TOs) and DPs~~During the 24 months prior to the effective date of Requirement R1, the applicable entities would be expected to participate in PC/TP processes to change the modeling data reporting requirements related to ~~DER and IBR developed during the 24 months prior to the effective date of Requirement R1~~IBRs and aggregate DERs and should be able to start working on data collection processes and methods. The applicable entities in Requirement R2 would then have an additional 12 months to complete and implement data collection prior to the compliance dates of Requirements R2, R3, and R4. This timeline also allows for the development of new data estimation processes developed under MOD-032-2 Requirement R2, Part 2.1~~.~~ and for the development of technical rationale to support the use of models included on the Unacceptable Model List maintained by the ERO, where applicable. Requirements adjusted in Reliability Standards IRO-010-~~5~~6 and TOP-003-8 may not be practical to implement prior to full implementation of MOD-032-2, and therefore ~~was~~were set to the same implementation timeline. One additional limitation the DT ~~noted~~considered is the requirement for all FERC Order No. 901 directives to be fully implemented by January 1, 2030, including those ~~covered by~~to be addressed by

future standard revisions that may be dependent upon the implementation of these standard revisions.

In summary, this implementation plan would provide a full 36 months for MOD-032 Requirements R2, R3, R4, IRO-010, and TOP-003 from FERC approval until data is required to be reported~~.~~ under the revised requirements. During the phased-in compliance period for Requirements R2-R4, entities shall continue to provide data and perform other required actions in accordance with specifications developed under Reliability Standard MOD-032-1, unless entities are able to comply with the revised requirements sooner.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource is provided below. Where the DT 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.

~~Initial Performance Dates~~

~~Entities shall not be required to comply with Reliability Standard MOD-032-2 Requirements R2, R3, and R4 relating to revised Planning Coordinator/Transmission Planner data requirements and reporting procedures as developed under Requirement R1 and Attachment 1, until 12 months after the effective date of Reliability Standard MOD-032-2.~~

~~Entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 during the phased-in compliance period for MOD-032-2 unless they are compliant with revised Planning Coordinator/Transmission Planner data requirements and reporting procedures under Reliability Standard MOD-032-2 Requirement R1.~~

Reliability Standard MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator and Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

During the phased-in compliance period, entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 unless they are compliant with revised Planning Coordinator/Transmission Planner data requirements and reporting procedures under Reliability Standard MOD-032-2 Requirement R1.

Definition – Distributed Energy Resource (DER)

Where approval by an applicable governmental authority is required, the definition of ~~DER~~Distributed Energy Resource (DER) shall become effective on the first day of the first calendar quarter that is after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard IRO-010-~~5~~6

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard TOP-003-8

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1

Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard IRO-010-~~4~~5

Reliability Standard IRO-010-~~4~~5 shall be retired immediately prior to the effective date of Reliability Standard IRO-010-~~5~~6 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard TOP-003-7

Reliability Standard TOP-003-7 shall be retired immediately prior to the effective date of Reliability Standard TOP-003-8 in the particular jurisdiction in which the revised standard is becoming effective.

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Unofficial Comment Form

Project 2022-02 Uniform Modeling Framework for IBR

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-02 Uniform Modeling Framework for IBR** by **8 p.m. Eastern, Wednesday, September 10, 2025.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Jordan Mallory (via email) or at 470-479-7538.

Background Information

As the penetration of distributed energy resources (DERs) continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk-Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the Bulk Electric System (BES). The North American Electric Reliability Corporation (NERC) System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DER.

Further, in Order No. 901 issued October 2023, The Federal Energy Regulatory Commission (FERC) directed the development of Reliability Standards to address concerns "related to Inverter-based Resources (IBRs) at all stages of Interconnection, planning, and operations." (Id. at P 25). Among other things, FERC directed NERC to develop requirements addressing the provision of IBR and DER data to the entities responsible for the planning and operation of the BPS. More information on the specific FERC Order No. 901 directives addressed through this project is available in the Project 2022-02 Consideration of Order No. 901 Directives.

Based on comments received from Draft 1 posting, the drafting team (DT) updated MOD-032-2 to incorporate requirement language from the ERO Acceptable Models List Criteria Document. The ERO Acceptable Model Lists Criteria Document has been renamed ERO Unacceptable Models List, and the process as to how documents are added or removed has been added to the MOD-032-2 Standard as a Supporting Document. The ERO Unacceptable Models List itself will be posted on the NERC website for entities to locate whenever needed. Requirement R1, Part 1.4 was added to draft 2 for the PC and TP to specify submission of standard library dynamic models, user-written models, or both. Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large interconnection-wide base cases. Allowing the specification of user-written models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. The DT also explicitly ensured the PC and TP authority require submission of both model types, if deemed necessary. Requirement R1, Part 1.4.2 is responsive to FERC concerns about model

usability and non-convergence by requiring PCs and TPs that accept user-written models to specify usability requirements and require appropriate model documentation and instructions.

In addition, the DT worked on Requirement R2, Part 2.1 estimation language based on feedback received. Requirement R2 was modified to require estimation of modeling data if the Responsible entity (typically the Transmission Owner or Distribution Provider) is unable to gather required data. FERC Order 901 requires the provision of data related to unregistered-IBR and IBR-DER that in the aggregate have a material impact on the BPS.[1] If the data is estimated, Requirement R2, Part 2.1 also requires the entity to provide an explanation of the limitations of the estimated data and the method used for estimation in line with the Order 901 directives[2]. The requirement language intentionally uses the phrase "unable to gather" to mirror the FERC Order 901 language. Limitations of the estimated data is intended to capture both limitations of the availability of data (including instances where there are legal or contractual prohibitions on requesting certain data, no mechanism to enforce collection, or incomplete records of what is connected), and limitations of any data provided (including partially missing or suspect data). Further, the addition of compliance abeyance language for the estimation process provides entities the opportunity to hone their estimation process without risk of penalty (provided they proceed in good faith). The approach directed by FERC is flexible as to whether the underlying unregistered IBR and DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the Distribution Provider and Transmission Owner applying a combination of approaches to source the data. The PC and TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

Lastly, revisions in the Reliability Standards TOP-003-8 and IRO-010-6 data specification standards specify that entities responsible for developing and distributing data specifications shall include requirements for model submissions consistent with the model submitted for planning purposes, as applicable.

[1] FERC Order 901 at P104 and P105

[2] FERC Order 901 P104: "if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation."

Questions

1. Do you agree with the proposed MOD-032-2 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the proposed IRO-010-6 and TOP-003-8 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-6, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed ERO Unacceptable Models List? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

   ☐ Yes
   ☐ No

   Comments:

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

   Comments:

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Violation Risk Factor and Violation Severity Level Justifications

Project 2022-02 Uniform Modeling Framework for IBR

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-02 Uniform Modeling Framework for Inverter-Based Resources (IBRs). 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 the Federal Energy Regulatory Commission (FERC)-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The drafting team applied the following North American Electric Reliability Corporation (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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R1 require model submission in accordance with the Criteria for Acceptable Models maintained by the ERO. This is similar to other sub-requirements in Requirements R1; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R1

Please refer to the VSL table below.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. “Load Serving Entity” was replaced with “Distribution Provider” from Requirement R2 in MOD-032-2. In addition, Requirement R2 added a sub-requirement requiring if entity is unable to gather unregistered IBR data or Distributed Energy Resource (DER) data to complete an estimate. These modifications align with the medium risk requirement and therefore, the VRF remained medium.

VSL Justification for MOD-032-2, Requirement R2

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R3 were administrative in nature; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R3

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSLs for MOD-032-1, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

VSL Justifications for MOD-032-1, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional sub-requirement to Requirement R1. The proposed VSL was modified to reflect the additional sub-requirement. It does not have an 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 updated sub-requirement requires the responsible entity to follow the Criteria for Acceptable Models document maintained by the Electric Reliability Organization. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner,

of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.

VSL Justifications for MOD-032-1, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 and a sub-requirement was added requiring if entity is unable to gather unregistered IBR data or DER data to complete an estimate. The proposed VSL was modified to reflect the additional sub-requirement language. It does not have an 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 updated sub-requirement requires the entity if it is unable to gather unregistered IBR data or DER data to complete an estimate. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 3			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

VSL Justifications for MOD-032-1, Requirement 3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by replacing Load Serving Entity with Distribution provider. The proposed VSL was modified to reflect this modification. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

IRO-010-5

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for IRO-010-5, Requirement R1

Please refer to the VSL table located below.

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R2

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VRF Justification for IRO-010-5, Requirement R3

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R3

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSLs for IRO-010-5, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

VSL Justifications for IRO-010-5, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

TOP-003-8

VRF Justification for TOP-003-8, Requirement R1

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R1

Please refer to the VSL table located below.

VRF Justification for TOP-003-8, Requirement R2

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R2

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R3

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R3

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R4

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R4

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R5

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R5

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSLs for TOP-003-8, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

VSL Justifications for TOP-003-8, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for TOP-003-8, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-8, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R2. The proposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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

NERC Project 2022-02 | MOD-032-2, TOP-003-8, and IRO-010-6
August 2025

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. It should be noted that Generator Owner (GO) applicability includes both Category 1 GO and Category 2 GO consistent with proposed revisions to the definitions of those terms developed under Project 2024-01 Rules of Procedure Definitions Alignment.

Additionally, the drafting team (DT) reviewed the dual applicability to Planning Authority (PA) and Planning Coordinator and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria are updated to use only a single term. The posted "Appendix 5B: Statement of Compliance Registry Criteria," dated June 27, 2024, still uses both terms and, arguably, the PA term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the DT excluded the explanatory language from MOD-032-2 Applicability Section.

Rationale for Distributed Energy Resource (DER) Definition

The DT has proposed that a definition for DER be added to the *NERC Glossary of Terms used in Reliability Standards* (NERC Glossary of Terms). The approved standard authorization request (SAR) to revise MOD-032, submitted December 2021, noted that "it may be needed (based on the discretion of the DT) to add a definition for 'Distributed Energy Resource (DER)' to the NERC Glossary of Terms" in conjunction with adding DER data to Attachment 1, the main purpose of this SAR.[1] The DT found it necessary to draft a DER definition to clarify the usage of this term within the standard. Further, the DT recognized benefits of a NERC Glossary of Terms definition to bring alignment and consistency of term usage across Reliability Standards. Additionally, the term Inverter-Based Resource (IBR) was recently defined in the NERC Glossary of Terms under Project 2020-06 for a similar reason. Finally, the DT was comprised of team members with adequate experience to propose a definition, including members of the NERC SPIDERWG and IEEE 1547 working group.

The DT proposes to define Distributed Energy Resource (DER) as follows:

"A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system."

[1] SAR title "MOD-032-1 Data for Power System Modeling and Analysis", submitted 12/15/2021. Available at: https://www.nerc.com/pa/Stand/Project202202ModificationstoTPL00151andMOD0321DL/2022-02_MOD-032%20SAR%20SPIDERWG_020122.pdf

In developing this definition, the DT considered various DER definitions utilized in the industry and discussed in the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Terms and Definitions Working Document, including the six other definitions described in Appendix D that were not adopted by SPIDERWG. Through this review, the DT determined each of these seven definitions would benefit from refinement to be most suitable for application in MOD-032 and future reliability standards more broadly. It is expected that most reliability standard revision proposals related to DERs would originate from the SPIDERWG. Thus, the DT's intent was to propose a DER definition that aligned with the SPIDERWG working definition, which explicitly excludes demand response and clarifies what is in scope and out of scope with respect to where a DER is connected, rather than the technology type.

The DT considered adopting a voltage threshold to define distribution. However, industry generally differentiates transmission from distribution based on the functional use of the system rather than technical specifications (e.g., voltage, active power, etc.). Setting aside the Bulk Electric System, that has a NERC definition, defining electric facilities as either transmission or distribution is often based on State law or regulations, ISO/RTO tariff, and/or utility tariffs. There are no conflicts in how applicable entities define distribution and transmission facilities for a given region, even if those definitions vary from region to region. Additionally, the DT considered an active power threshold to define DER and concluded that DER technologies can vary in size, and a threshold might inappropriately exclude technologies that are DER[2]. At the same time, the DT understands that certain applications of DER data, for instance determining when or how a Transmission Planning (TP) or Planning Coordinator (PC) includes DERs into planning processes (e.g., TPL-001), may include active power or other TP or PC defined thresholds.

The DT considered defining DER based on the resource not being connected to the Bulk Power System (BPS), similar to the IEEE 1547-2018 definition that uses "not directly connected to the BPS" to describe DERs. However, the NERC Glossary of Terms definition of BPS does not provide specificity that would enhance a definition of DER beyond an undefined term that is generally used in industry. The phrase "distribution system" was selected to expressly describe the type of electric facilities that would cause a resource to be defined as a DER, if interconnected to those facilities.

The DT recognizes that "distribution system" is not defined in the NERC Glossary of Terms and that the SPIDERWG proposed a definition.[3] The DT reviewed the SPIDERWG definition and concluded that it would not clarify the term DER. The SPIDERWG use of the term "transmission-distribution" interface within a definition of "distribution system" could be considered a circular reference that causes ambiguity. The DT is not proposing a definition for distribution system given any proposed definition could be of limited benefit for clarifying the proposed definition for DER.

Below is a summary of the rationale for the DT departing from each of the seven definitions when proposing a new DER definition.

[2] NERC has published a study recommending that a zero MVA threshold be used when collecting DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

[3] SPIDERWG definition of "distribution system": The electrical facilities that are located behind a transmission-distribution transformer that serves multiple end-use customers. https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

SPIDERWG definition

After considering the SPIDERWG definition, the DT determined it provided a useful foundation but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term included transient types of DER power beyond generation and storage, and it included sources of back-up power that would have no potential grid impacts.

The DT chose to refer to a generator or storage technology specifically, rather than use the SPIDERWG language of "source", to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.). A DER can use various technologies including synchronous machines, induction machines, and power inverters/converters (i.e., IBR). Different types of DERs can utilize a wide range of energy sources including, but not limited to, natural gas, diesel, hydro, storage, wind, and solar. Additionally, the DT intention was to ensure that the scope included facilities "connected behind the meter of an end use customer" that may export Real Power to the power system or offset Real Power load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load. While not finalized, it is the drafting team's understanding that this determination is consistent with recent proceeding from the IEEE 1547 revision Working Group. To exclude transmission connected load customers that have onsite generation or storage resources, the DER definition clarifies that the behind-the-meter customer "is supplied from a distribution system".

The DT included the language "in non-isolated parallel operation with the Bulk-Power System" to indicate that a distributed energy resource with potential BPS reliability impacts is only one that has electrical connectivity to the BPS. A resource that is only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BPS and, therefore, is not of interest from a BPS-reliability perspective. The DT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry. The DT intentionally avoided the term "directly connected" to differentiate electrical connectivity from an electrical connection point. The phrase "connected to the distribution system" speaks to electrical connectivity and the subsequent phrase "including one connected behind the meter of an end use customer" clarifies this connectivity includes a resource directly connected to a customer system (i.e., behind the meter).

IEEE 1547-2018

The DT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the issues identified above. The DT incorporated the explicit reference to generation and storage aspect of the IEEE definition. Further, the IEEE concept of "capable of exporting active power to an EPS" informed the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the DT definition.

At the same time, the DT did not view the IEEE definition as suitable for the DT's intended use as written. The IEEE term qualifies the DER connection point as "not directly connected to a bulk power system" which the DT viewed as potentially ambiguous. Instead, the DT opted for the "connected to a distribution system" language to point to the electric system location, and how facilities at that location are classified, as a key

concept in differentiating DERs from other generators and energy storage technology. The DT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a NERC Glossary of Terms DER definition.

Federal Energy Regulatory Commission (FERC) Energy Primer
The DT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability use cases, the DT and SPIDERWG definitions target sources of electric power, with the DT narrowing this definition to be only sources "capable of providing Real Rower." After considering the FERC definition, the DT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)
NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the DT concluded it is too broad.

NERC DERTF
The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the DT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric System" which the DT views as overly broad.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be based on California legislation and includes energy efficiency, EVs, demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the NERC Glossary of Terms.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition's exclusion of a large portion of DER (i.e., retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study.

Figure 1 below provides a graphic illustration of the DER definition and the intended scope of facilities that would fall under the proposed definition. Figure 2 below shows that the proposed DER and IBR definitions are compatible, but distinct. Some resources may be classified as a DER, but not an IBR; some resources may be classified as an IBR, but not a DER; some resources may be classified as both a DER and an IBR. This relationship between the definitions and the existence of non-IBR storage solutions informed the phrasing of "generator and energy storage technology" to ensure all generators and all storage devices are included, even if they do not meet the definition of IBR. Note that in Figure 2, "distribution-connected" is shorthand for connected to the distribution system and "bulk system-connected" refers to resources connected to the transmission system.

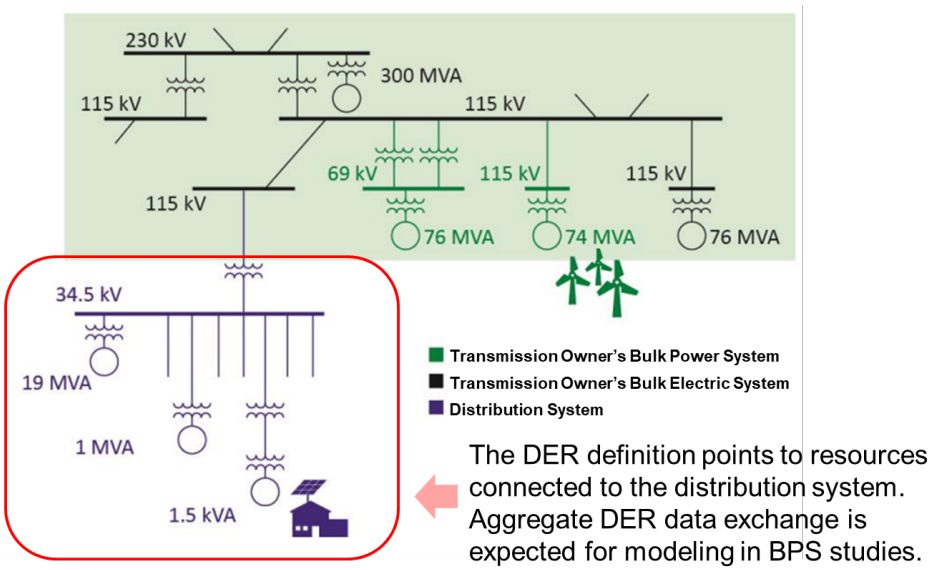


Figure 1: DER Definition Illustration

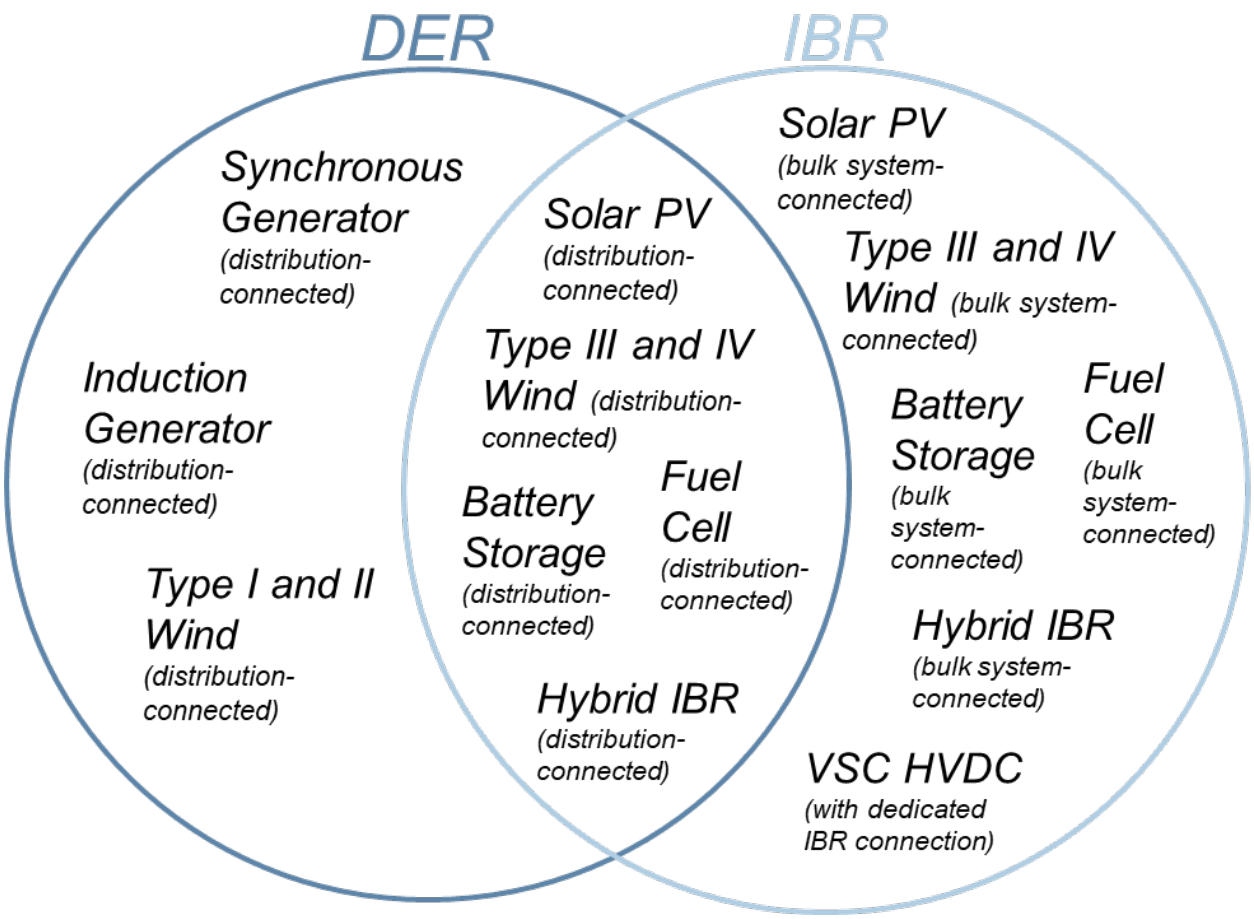


Figure 2: DER and IBR Definition Compatibility

Rationale for Modifications to Requirement R1

Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the "entity" to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement. Such flexibility could allow the TP or PC to directly estimate data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes and aggregated DERs connected to unregistered Distribution Providers based on any information received in accordance with their data requirements and reporting procedures. As an example, data received from DPs in the area that can be assumed to have similar DER adoption profiles. FERC Order 901 uses the phrase "unregistered IBR" but given this is an undefined term and the drafting team received opposition to explaining that term in a footnote, the phrase was replaced in the standard with "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes." This is the intent of all further references to "unregistered IBR" in this technical rationale.

FERC Order 901 directs NERC to develop reliability standards that require "the use of approved industry generic library IBR models".[4] However, pre-defining a limited set of models (i.e., a library of models) that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To align with industry practices while addressing the directives of the FERC Order, the DT incorporated elements from the NERC Dynamic Modeling Recommendations into Requirement R1, Part 1.4, rather than defining an inclusive model library. The DT supports the approach and views it as aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 and June 3-5 NERC Industry Engagement Workshops.[5][6] For instance, Order 901 P125 requires "the sole use of nation-wide approved component generic library models" whereas workshop participants raised issues surrounding timelines for approving library models that reflect new IBR products, the accuracy of library models for certain products, timelines associated with updating library models, and referencing a document outside of the standard that could be changed by a process also outside the standard, among other issues.

[4] FERC Order 901 at Paragraph 122.
[5] NERC Industry Engagement Workshop–Reliable IBR Integration and Milestone 3 of FERC Order 901 Agenda
[6] Milestone 3 of FERC Order 901 NERC Industry Engagement Workshop June 3-4 PowerPoint

To address these concerns, Requirement R1, Part 1.4 includes requirements for the PC/TP to specify submission of standard library dynamic models, user-defined models, or both. The phrase user-defined models should be considered interchangeable with user-written models, equipment-specific models, and other such terms. The phrase "user-defined models" was used in MOD-032-2 based on language in FERC Order 901.[7] Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. The DT also explicitly ensured PC/TP authority to require submission of both model types, if deemed necessary. Requirement R1, Part 1.4.2 is responsive to FERC concerns about model usability and non-convergence by requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions.

Rationale for Modifications to Requirement R2

Requirement R2 was modified to require estimation of modeling data if the Responsible entity (typically the Transmission Owner or Distribution Provider) is unable to gather required data. FERC Order 901 requires the provision of data related to unregistered-IBR and IBR-DER that in the aggregate have a material impact on the BPS.[8] If the data is estimated, Requirement R2 Part 2.1 also requires the entity to provide an explanation of the limitations of the estimated data and the method used for estimation in line with the Order 901 directives.[9] The requirement language intentionally uses the phrase "unable to gather" to mirror the FERC Order 901 language. Limitations of the estimated data is intended to capture both limitations of the availability of data (including instances where there are legal or contractual prohibitions on requesting certain data, no mechanism to enforce collection, or incomplete records of what is connected) and limitations of any data provided (including partially missing or suspect data).

The exact method used for estimation is intentionally left open given the varying levels of data available across the ERO footprint. A few possible examples include:

- A full list of DERs broken down by resource type with limited fields missing and assumed based on other characteristics.
- Real Power capability by resource type with approximate percentage of the resource compliance with various IEEE 1547 versions used for dynamic performance assumptions (known or assumed based on installation date).
- Count of resources by resource type with average size used to estimate Real Power capability.
- Derive values for unregistered DPs based on average of registered DPs in the area (scaled based on total system size).
- Solar capability estimated based on satellite imagery of rooftops.

[7] FERC Order 901 at P124
[8] FERC Order 901 at P104 and P105
[9] FERC Order 901 P104: "if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation."

- Assumptions of regional/national average IBR-DER penetration levels.

Additional guidance for DER estimation can be found in NERC SPIDERWG Reliability Guidelines on the topic.[10]

The DT views the introduction of this estimation provision as alleviating previously expressed compliance obligation concerns around challenges in collecting data for DERs connected to unregistered entities. Further, the addition of compliance abeyance language for the estimation process provides entities the opportunity to hone their estimation process without risk of penalty (provided they proceed in good faith). The approach directed by FERC is flexible as to whether the underlying unregistered IBR and DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP and TO applying a combination of approaches to source the data. The PC and TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

While the FERC Order 901 directives only addressed IBR-DER, meaning that DER technologies based on induction generators or synchronous generators are not explicitly addressed, Project 2022-02 is also assigned a SAR that requires DERs to be addressed in MOD-032 more generally, and the inclusion of all DERs in this revision of the standard removes the need for a second modification under this project. The DT found it practical to have a consistent estimation framework applicable for all DER technologies when DER data cannot be gathered. Therefore, Requirement R2 was intentionally written to have requirements for estimating DER data regardless of the technology type, when an applicable entity is unable to gather the data. The approach FERC directed NERC to use forms the basis for this uniform approach.

Given the challenges with collecting complete and accurate DER data, the DT would still recommend that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would delay the project beyond the FERC Order 901 Milestone 3 timeline. The DT considered adding "UFLS-Only Distribution Provider" to MOD-032-2 applicability to reduce (but not necessarily eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, the UFLS-Only Distribution Provider can only be obligated to provide data directly associated with UFLS programs (essentially the data identified in Attachment 1 Dynamics Column 10b). Provision of such data in the absence of the other DER data identified in Attachment 1 would not be particularly useful for planners.

Requirement R2, Part 2.2 was added to confirm the relationship and consistency between MOD-026 and MOD-032 indicated in FERC Order 901 Paragraph 143[11]. The DT believes that the intent of FERC Order 901

[10] Reliability Guidelines, Security Guidelines, Technical Reference Documents, and White Papers

[11] FERC Order 901 P143: ""Regarding EPRI's recommendation to require appropriately parameterized plant models, we agree that the model verification process of an IBR model should include steps to ensure that responsible entities provide both verified and appropriately parameterized models. Additionally, we agree with IRC's recommendation that the plant model verification process should include requirements for equipment to be represented as installed in the field. While we decline to include this level of detail in the directive to NERC, we nonetheless direct NERC to establish a standard uniform model verification process. A uniform model verification process will

is to ensure that accurate (validated and verified) models are collected under MOD-032. However, facility models submitted under MOD-032 are often submitted before physical validation can be completed (e.g., for planned facilities). Part 2.2 requires the model submitted by the functional entity be the model that was verified and validated (and accepted by the TP) in accordance with MOD-026, if available.

Requirement R2, Part 2.3 introduces a reference to the Unacceptable Models List (UML) maintained by the ERO. The DT concluded that it would be most appropriate for NERC to maintain the UML as a separate document that could be updated more quickly and frequently than the standard development process. However, any changes to the process for modifying the UML, that is incorporated into MOD-032-2 as a supporting document, would need to be approved through the standard development process.

It is also recognized that models on the UML may be the best available for some generators, particularly for some synchronous generators and for units manufactured by companies that are no longer in business. Part 2.3 allows for the submission of such a model if accompanied by a technical rationale justifying its use. The requirement does not intend any specific level of scrutiny for this rationale, but it also does not prevent the PC or TP from identifying technical concerns with the model or the rationale per Requirement R3. This rationale could include notation of prior usage for synchronous generation as well as models that have been recently added to the UML without time to procure an updated model prior to reporting. A MOD-032 supporting document defines the process for modifying the UML as a sufficient safeguard to prevent arbitrary or unvetted modifications being made to the UML.

Rationale for Modifications to Requirement R3

Requirement R3, Part 3.1 was modified to include the phrase “that is responsive to the technical concern”. The ultimate intent of R3 is to resolve technical concerns that are identified by the PC or TP. However, model providers may not always be able to know that their update or explanation will resolve the planner’s technical concern. The intent of this addition is to convey that the model provider’s obligation does not simply end with providing a response, but further information exchanges between the planner and model provider may be necessary to resolve the technical concern.

Rationale for Modifications to Attachment 1

Data items specific to IBRs and DERs were added to MOD-032-2 Attachment 1: Data Reporting Requirements.

The DT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with items are only presented in one column (i.e., some sub-bullets are only listed in the “steady state” column even though the data is also relevant to “dynamics” and/or “short circuit”). This long-standing approach was made explicit in footnote 1 of the MOD-032-2 Reliability Standard.

ensure that all entities use the same set of minimum requirements to verify that all generation resource (i.e., synchronous and non-synchronous) models are complete and that the models accurately represent the dynamic behavior of all generation resources at a sufficient level of fidelity for Bulk-Power System planners and operators to perform valid interconnection-wide, planning, and operational studies. Therefore, we direct NERC to define the model verification process and to require consistency among the model verification processes for existing Reliability Standards (e.g., FAC-002, MOD-026, and MOD-027) and any new or modified Reliability Standards.”

The format of Attachment 1 was modified to minimize replicating footnotes applicable to multiple items by adding a new footnotes section (Attachment 1 Data Reporting Requirements Footnotes) to the document. Along with the reformatting, language was added to the introductory paragraph to clarify that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1.

Modifications for IBR

To incorporate IBR within Attachment 1, "and storage units" was added to generating units in the steady-state column under item 3. "Generating units" already incorporates IBR generators such as solar and wind. Storage is typically not classified as a generation resource because it has no primary energy source and consumes more energy than it injects when considering losses. Therefore, the DT found it necessary to include storage explicitly. Footnote 4, associated with "Generating units and storage", was also updated to explicitly identify IBR as an applicable technology for the item and remove pumped storage now that storage is explicitly identified.

The dynamics column was updated to replace "photovoltaic systems" (PV) with "Inverter-Based Resources" under item 7. IBR encompasses PV, resulting in PV technology still being included under this new item.

The three following sub-items were added to dynamics item 7 based on specific language from the FERC Order 901, Paragraph 141.[12]

- IBR capabilities related to momentary cessation,
- Tripping, and
- Ride-through

"Frequency control" was added as a sub-item because frequency response of IBR is important for studying system reliability. For instance, a 2024 NERC Lessons Learned report shows how IBR frequency response can affect system performance.[13] Frequency control encompasses primary frequency response, fast frequency response (e.g., IEEE 2800-2022, Subclause 6.2), and potentially other frequency responsive controls (e.g., "grid-forming" virtual synchronous machine controls).

"Voltage control" was added to encompass reactive power and voltage control that may affect the dynamic or steady state performance of the plant. NERC's Level 3 Alert on Inverter-Based Resource Performance and Modeling, issued May 2025, contains Essential Action #1 indicating the importance of voltage control performance for normal and post-disturbance operations.[14]

[12] FERC Order 901, P141 states that IBR and IBR-DER data must include "momentary cessation and/or tripping, and all ride through behavior."
[13] NERC, Lessons learned, Incorrect IBR Primary Frequency Response Logic Caused Negative ACE. Available at: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20240501_Incorrect_IBR_Primary_Frequency_Response_Logic_Caused_Negative_ACE.pdf
[14] NERC, IBR Performance and Modeling, Level 3 Alert. May 2025. Available at: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/Level%203%20Alert%20Essential%20Actions%20IBR%20Performance%20and%20Modeling.pdf

In order to clarify dynamics item 6, "wind plant model", to not overlap with the new IBR item 7, type 1 and type 2 wind turbines are specifically called out under item 6. These technologies are not IBR.

Footnote 5 indicates that the PC/TP data requirements and reporting procedures need to account for IBRs that are not DERs and do not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. It also indicates that the TO is typically responsible for such data.

Modifications for DERs

Item 9, "Aggregate Distributed Energy Resource (DER) data" was added to the steady state column with location, real power capability, and DER type (solar, battery, diesel generator, etc.) specified as required subitems. The DT selected these subitems as the minimum information needed to use data and make assumptions for power system modeling and analysis; the PC/TP have the authority to request additional data items as deemed necessary.

The intent is that relevant DER data be available and represented in models of the interconnected transmission system consistent with the NERC approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum information needed to reasonably represent DER in transmission system models. "Aggregate DER" is specified in item 9 to indicate aggregate DER data, rather than individual DER facilities, would be represented in most PC/TP study models.[15] The word "aggregate" was specifically added to Attachment 1 to clarify this point based on industry comments and to align with FERC Order 901. However, Requirement R1 provides the PC and TP great flexibility in developing data requirements and reporting procedures that align with local practices and needs, in addition to the required items listed in the Requirement R1 Parts. Given industry comments on DER data availability, and FERC Order 901 directives, a process is needed for estimating DER data when an entity is unable to gather it. The process for estimating those values is referenced in Requirement R2, Part 2.1.

Footnote 3, associated with "aggregate demand", was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DERs is not consistent with a modeling framework that explicitly represents DERs.

Dynamics item 5, previously "demand", was updated to be "aggregate demand" to be consistent with the steady state column and general industry practices of modeling load dynamics for aggregate demand (e.g., composite load model).

Dynamics item 10 was updated to include "Aggregate Distributed Energy Resource (DER) data" along with the subitems: "parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control"; and "indication whether DERs are subject to tripping in conjunction with UFLS or UVLS".

[15] In certain circumstances (e.g., a very large DER), a TP or PC may decide to represent the individual DER. However, the DT anticipates most DER information will be aggregated based on PC and TP planning practices.

Momentary cessation, tripping, and ride-through of aggregate DERs is needed for dynamics studies. For instance, NERC's Lessons Learned, LL20220401 "Distributed Energy Resource Performance Characteristics during a Disturbance" provided information following the loss of 300 MW of DERs following a system fault. The report indicated that:

> "There is a need to understand how distribution system connected generation, and loads will behave and how they can accurately be modeled under expected system contingencies. Entities should know the behavioral characteristics of DER inverters on their system (both new and old) as well as their number, capabilities, and locations and then report that information to their Balancing Authorities and Reliability Coordinators so their models can be accurate".

Voltage control of DERs can alter the exchange of reactive power between distribution and transmission systems and may affect the results of reliability studies. Examples are described in the approved Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources.

Frequency control must be accounted for because DER interconnection under different standards (e.g., IEEE 1547-2003 versus IEEE 1547-2018) have different frequency response characteristics that may affect dynamics study results. Frequency control in this case typically refers to the frequency-droop characteristic outlined in IEEE 1547-2018, Subclause 6.5.2.7 and adopted in many jurisdictions. However, should other DER frequency controls become common in industry, those would also fall under this category.

As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DERs subject to each UVLS/UFLS tripping stage should be identified.

In response to comments, the DT added Footnote 7, which explicitly confirms the PC/TPs discretion to specify aggregation thresholds below which they do not consider DER data necessary to collect. Based on the 0 MVA threshold recommendation noted previously, this threshold should only be established following consideration of that DER Modeling Study Report[16].

Inferring DER Capabilities

Item 10 in the dynamics column indicates that aggregate DER dynamics modeling data may need to be inferred due to data availability and practical limitations. As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DERs may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DERs installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate Ride-through characteristic representation for DERs in that area could be inferred by the in-service date of the DERs. However, the PC/TP modeling data requirements and

[16] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

Entity responsibilities and coordination

Footnote 6 indicates that the PC/TP data requirements and reporting procedures need to account for situations where DERs are connected to the system of an unregistered DP. When a DER is connected through a registered DP (directly connected to that DP, connected to an unregistered DP that is connected to that DP, or behind the meter of an end-use customer of either) that DP is the typical responsible entity for collecting and providing the DER data. Further, the TO would be the typical responsible entity if there is no system owned by a registered DP between the DER connection point and TO system. This clarification is necessary to reduce the possibility of DERs on the system being unaccounted for by any entity. The DT was responsible for the FERC Order 901 directive requiring an entity to be identified when DERs had no registered DP. It is possible that a company that is a registered Generator Owner may also own resources that do not meet the criteria for registration. That would not change the responsible entity identified per R1, though the owner is encouraged to provide all relevant data to that responsible entity. This point applies broadly, where nothing in the standard is intended to preclude coordination among entities to make sure the responsible entity has the best available information to provide.

The PC/TP may have access to sufficient data for modeling certain DERs through alternative means (e.g., direct registration of DERs or DER aggregators in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data, but care will be needed to ensure DERs are not double counted. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DERs that are excluded from the DP/TO obligation for providing DER modeling data. This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its PC and TP under Requirement R1.

It should be noted that the MOD-032-2 modifications do not change the classification of unregistered IBRs or DERs to become BES facilities subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered entities (typically DPs or TOs if identified as the responsible entity by the PC/TP) to provide basic information about unregistered IBRs or DERs that are connected to their systems so they can be properly represented in Interconnection-wide cases. There are already existing requirements for such entities to provide information about load connected to their systems. Like load, unregistered IBRs and DERs are not generally considered to be BES facilities. However, BES reliability assessments require an accurate representation of aggregate load, unregistered IBR, and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient data is available to the PC/TP so that appropriate unregistered IBR and DER representations can be included in their BES reliability assessments as required by FERC Order 901 and system planning needs.

IRO-010-6 – Reliability Coordinator Data Specification and Collection; and TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

The DT reviewed existing IRO-010 and TOP-003 versions and found that both standards had broad requirements language that encompassed generation and storage resources, including IBR. Nevertheless, to ensure no ambiguity that FERC Order 901 requirements are met, the DT included explicit references to IBR-specific data and parameters and pointed to the uniform framework through an alignment between planning and operations models.

Rationale for Modifications to add "IBR-specific data and parameters"

The phrase "IBR-specific data and parameters" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.1
- TOP-003-8 Requirement R1, Part 1.1
- TOP-003-8 Requirement R2, Part 2.1

These modifications were made in response to FERC Order 901 directives related to the inclusion of IBRs in operations models.[17] The phrase "IBR-specific data and parameters" in the revised IRO-010-06 and TOP-003-8 is intended to reflect what FERC describes in the order as "IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions".

Rationale for Modifications to add reference to MOD-032

"Requirements for model submissions to be consistent with the model submitted for planning purposes, as applicable" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R2, Part 2.5.3

These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Models submitted for planning purposes are typically in accordance with MOD-032, though additional standards or regional requirements may apply. Simulation time constraints in an online operations environment may warrant a reduced model structure complexity; such models may differ from, but should still be consistent with, more complex modeling that is submitted under MOD-032. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. For example, consistent models would not be appropriate if an update was made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation.

[17] FERC Order 901 Paragraph 122 and Paragraph 161

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of FERC Order No. 901 Directives

Milestone 3: Project 2022-02 Uniform Modeling Framework for IBR
August 2025

On October 23, 2023, FERC issued a Final Rule, Order No. 901, directing the North American Electric Reliability Corporation (NERC) to develop new or modified Reliability Standards that address aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project has a FERC regulatory deadline of November 4, 2025. Below provides the directives from FERC Order 901 along with the drafting team's (DT's) consideration of the directives.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
P7. "… Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate…"	IRO-010 MOD-032 TOP-003	A timeline has been drafted to meet the regulatory deadline of November 4, 2025. Completed tasks listed below. • An industry workshop completed January 14-17, 2025. (outreach) • Many virtual DT meetings completed weekly from January – March 2025. (publicly posted) • In-person DT completed February 11-13, 2025. (publicly posted) • Industry Webinar March 6, 2025. (publicly posted) • DT outreach with trade groups and entities March 3-14, 2025 • Industry comment and ballot period April 17-May 16, 2025. (publicly posted)

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		• A second industry workshop completed June 3-5, 2025. (publicly posted) • Many virtual meetings were completed weekly from May 19-July 23, 2025. • Industry outreach with trade groups and entities July 3-23, 2025. • Industry comment and ballot period August 8-September 10, 2025.
P76. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information, and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System. As several commenters indicate, ensuring the sharing of appropriate IBR modeling data is critical to create and maintain the models used in reliability studies, and in turn to ensure that Bulk-Power System transmission planners or operators are able to plan for, operate, and reliably integrate IBRs onto the Bulk-Power System."	IRO-010 MOD-032 TOP-003	**Theme:** Inverter-Based Resource (IBR) /Generator Owner to provide specific modeling data. IRO-010 and TOP-003: • While TOP-003 and IRO-010 allow any data to be requested, the DT felt it was important to add "IBR-specific data and parameters" specifically to IRO-010-6 Requirements R1, subpart 1.1 and TOP-003-8 Requirement R1, subpart 1.1 and Requirement R2, subpart 2.1 to ensure it is clear what data may be specifically requested to address FERC Order No. 901. In addition, IBR encompasses IBR-DER, and this information could be requested. • The DT considered adding a new subpart at the end of Requirement R1 (e.g., Part 1.6), but after reviewing requirement language, the DT determined the data and information lists within the existing subparts were the appropriate place to capture IBR-specific modeling data and parameters.

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		MOD-032: • Generator Owner and Generator Operator – The DT decided to maintain applicability for just the Generator Owner and did not add Generator Operator as a functional entity to the applicability section. If data is needed from the Generator Operator, then the Generator Owner can reach out to the Generator Operator for necessary data via contractual obligations, etc. The DT does not find it necessary to require two applicable entities when one oversees the other. • The DT modified Attachment 1 to include generation and storage units, removed photovoltaic system (covered within IBR) and added Inverter-Based Resources. The wind turbine was updated for clarity that it is for Type 1 and Type 2, which is not included in the IBR definition.
P77. "With regard to AEU and ACP/SEIA's comments that the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners and operators, we believe that this request may already be addressed through each transmission planner's existing processes. For example, the New York Independent System Operator (NYISO) and CAISO both have processes for obtaining such data after demonstrating a need for the specific information requested and that the required information protection and non-disclosure agreements are signed. Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's	MOD-032	**Theme:** Information going from Transmission Owner to Generator Owner/Generator Operator (consider): MOD-032 • There is no specific requirement within MOD-032 that requires Transmission Owners to share data with the Generator Owners and Generator Operators (and such a requirement would not be aligned with the purpose of MOD-032). However, Transmission Planners and Planning coordinators have a framework where requests for data can be sent for inclusion for the Interconnection-wide models. At this time, the DT does not see a need for a requirement to be drafted requiring Transmission Owners to provide data to Generator Owners and Generator Operators. The DT believes this is most appropriately addressed

FERC Order No. 901 Directives		
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suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." **P74.** "AEU and ACP/SEIA ask that, in addition to data provision requirements for generator owners and operators, the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners. For example, AEU explains that generator owners and operators also require data from transmission owners to support accurate modeling and performance, e.g., short circuit data, grid data for offshore wind, information on other power electronic devices around the IBR plant, and voltage harmonics. AEU adds that putting requirements on transmission owners would be consistent with revisions being developed for NERC's Modeling, Data, and Analysis (MOD) Reliability Standards."		through processes that exist outside of the MOD-032 Reliability Standard and concurs with the suggestion in P77 that these processes are already in place.
P78. "Commenters raised general concerns that mandating specific modeling and data submissions would reduce the flexibility and discretion of transmission planners and operators to identify the information they need. We find that, given the need for IBRs to operate in a predictable and reliable manner to ensure the reliable operation of the Bulk-Power System, it is necessary to establish uniform, minimum categories or types of data that must be provided so that Bulk-Power System planners and operators can predict the behavior of all IBRs. As discussed in more	MOD-032 TOP-003 IRO-010	**Theme:** Individual use of approved IBR models. (Uniform modeling framework) **Applicability:** Transmission Planner and Transmission Operator • Modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establish an improved uniform modeling framework. IBR has been included in Attachment 1 of MOD-032 under steady state (item 3), dynamics (item 7), and short circuit specifying the minimum types of IBR data and capabilities that need to be collected as required per FERC Order No. 901.

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detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions."		• Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.
P86. "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."**	TOP-003 IRO-010	**Theme:** Disturbance and monitoring (Consider) (real-time operations) **Applicability:** Generator Owner TOP-003/IRO-010 • TOP-003 and IRO-010 Reliability Standards are already structured in an open way so that any type of data needed can be requested at any time. In addition, transmission of information from the plant level is generally dealt with via interconnection agreements and does not rise to the level of a requirement being needed at this time. Lastly, PRC-028 PMU devices must be installed for every IBR installation. These additional monitoring devices will allow additional data requests related to those devices, if the applicable entities find that useful. Because of the two items above (the open method for data requests and the PRC-028 PMU devices), the standard balances the needs for the Transmission Operator to gather the data deemed necessary for reliability without uniform burden on all generating facilities.
P102. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal, with modification. Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1)	MOD-032 IRO-010 TOP-003	**Theme:** 1) Transmission Owner directed to provide data for unregistered IBR and 2) Distribution Provider directed to provide data for IBR-DER **Applicability:** Transmission Owner and Distribution Provider

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transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System."		• The DT focused on the MOD-032 standard to address this directive from FERC. The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the MOD-032 standard. In response to comments seeking more precision, the MOD-032 standard uses the phrase "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes" to refer to the IBR resources encompassed by the term "unregistered IBR" in Order No. 901. • While the DT agrees that the Transmission Owner would be the typical entity for providing unregistered IBR data and the Distribution Provider would be the typical entity to provide DER data (as noted in Attachment 1 of MOD-032), the DT modified the Requirement language in response to comments to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2. Determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System, requires engineering judgment and is not something that would be appropriate to precisely specify in a reliability standard. Thus, Attachment 1 footnote 7 was added to explicitly allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard), and to add references back to the MOD-032 standard. The DT determined that the IRO-010 and TOP-003 standards already included language in place to address IBR impacts.

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P104. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) Estimation, if not able to get data from unregistered IBRs, 2) an explanation of the limitations of the availability of data, 3) explanation of the limitations of any data provided by unregistered IBRs, and 4) method for estimation. (directive) **Theme 2:** Implement a process or mechanism by which Transmission Owners would receive modeling data and parameters. (consider) **Applicability:** TO • The DT added Requirement R2, Part 2.1 allowing the functional entity to use the method of estimation should it find itself in a place unable to gather unregistered IBR data or DER data. However, it must include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. • In addition, the DT added an explanation of the resources that are intended to be captured. In proposed MOD-032, "unregistered IBR" are described as IBRs that are not Distributed Energy Resources, as the DT proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as owning either category 1 or category 2 assets). As suggested by commenters, the DT has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application. • While previous drafts of the MOD-032 standard used the shorthand phrase "unregistered IBR" to establish consistency with FERC Order No. 901, with the more fulsome description of

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the reliability of the Bulk-Power System. To support this data collection, we further direct **NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."**		those resources in the footnote, the DT moved this description to the requirement text (in lieu of the phrase "unregistered IBR") in response to comments. • It is important to note that Order No. 901 predated the changes NERC made to the Rules of Procedure to ensure that the owners and operators of such IBR resources would be registered with NERC for mandatory compliance purposes. NERC does not register IBRs as resources, but rather the owners of such resources based on the registry criteria for Generator Owner and Generator Operator. There are two categories of each: owners and operators of BES Facilities (category 1 GOs/GOPs); and owners and operators of 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 (category 2 GOs/GOPs). In Order No. 901 parlance, ownership or operation of IBR resources meeting these criteria would require owner/operator registration and therefore would be considered "registered IBRs". In Order No. 901 parlance, ownership or operation of IBR resources that do not meet these criteria but are connected to a transmission system (i.e., are not Distributed Energy Resources) would not require owner/operator registration and therefore would be considered "unregistered IBR." • The DT discussed implementing a process or mechanism by which Transmission Owners would receive modeling data and parameters in depth. It was determined that if a TO is unable to gather data for unregistered IBRs and DERs, it is better to not

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		mandate a specific process for how Transmission Owners acquire or estimate data. Obtaining data for unregistered IBRs should not pose a significant challenge because such facilities are likely directly connected to a TO system and provision of necessary data should be specified in interconnection agreements or other contracts. Obtaining data for DERs would be more challenging as these facilities are connected to the TO system through a separate unregistered DP. In such cases, it is prudent to allow various estimation methods to be used. • The IRO-010 and TOP-003 Reliability Standards are drafted in a way that is open-ended and allows the respective applicable entities to request data needed. However, project 2022-02 DT added "Inverter-based Resource (IBR) specific data and parameters" to ensure it is clear that entities can request data when needed for operations assessments. To the extent modeling is needed, it should be consistent with modeling data provided under MOD-032 modeling framework. Therefore, the DT made changes to the IRO-010 and TOP-003 standards to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes under MOD-032, as applicable.
P105. "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. (Directive) **Theme 2:** Consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters. (Consider)

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modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."		**Applicability:** Distribution Provider The DT added a new Requirement R2, Part 2.1 that if the responsible entity is unable to gather unregistered IBR data (*see description above*) or DER data and provide it to the Transmission Planner and Planning Coordinator, as specified in the data requirements and reporting procedures developed under Requirement R1, the responsible entity shall provide an estimate of the modeling data and parameters and include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. The DT discussed the possible mechanism by which Distribution Providers would receive modeling data and parameters. The DT did not feel this rose to the level of a requirement as the Distribution Provider can ask for the modeling data and parameters from the respective entity.
P106. "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead	MOD-032 IRO-010 TOP-003	**Theme:** Who is the responsible entity when no registered DP of IBR-DER (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation. • After much deliberation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for collecting and providing data for DERs

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to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."		connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." • The DT asked industry the following question: "Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system?" Some commenters agreed that the TO is the correct entity who should gather data if there is no associated registered DP between the DER connection point and the TO system. However, many comments received stated that the TO has no authority to collect data, and the following entities would be better suited to gather the data needed: Registered DP, Balancing Authority, Planning Coordinator, LSE, Generator Owner, Transmission Operator, and Resource Planner. Based on this feedback, the DT modified the Requirement language to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2.
P108. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request	MOD-032 IRO-010 TOP-003	**Theme:** Minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers that are necessary to predict the behavior of all

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that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear. As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions. By contrast, we believe that a directive to task distribution providers as the appropriate registered entity to collect and share the modeling data and parameters of IBR-DERs in the aggregate is preferable to deferring to the stakeholder process as suggested by APS. The distribution provider, as the entity providing and operating the lines between the transmission and distribution systems, is the entity best situated to have access to the data necessary for accurate estimation and, other than Indicated Trade Associations that suggested the piecemeal approach already discussed above, no commenter identified other potential entities as an equally efficient option."		IBRs and to ensure that compliance obligations are clear (ERO Approved Acceptable Criteria for Models/IEEE1547 ref./modify req./Tech rationale) **Applicability:** Transmission Planners, Transmission Operators, Transmission Owners, and Distribution Providers • The DT added Requirement R1, Part 1.4 to specify dynamic model submission requirements in Planning Coordinator/Transmission Planner data requirements and reporting procedures. • The focus of Requirement R1 Part 1.4 is obtaining accurate and usable models for IBRs. New Requirement R2 Part 2.3 provides that models with known deficiencies, such that the ERO included them on the Unacceptable Model List, shall not be submitted without technical justification. • Attachment 1 was modified to categorize the types of data required as per the directive (IBR, aggregate DER, Storage) necessary to facilitate model development. • Requirement R2, Part 2.1 requires entities to estimate unregistered IBR and IBR-DER data if the entity responsible for providing such data is unable to gather it.
P122. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop	MOD-032 IRO-010	**Theme**: Require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-

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new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."	TOP-003	circuit, and dynamic conditions when developing planning, operations, and Interconnection-wide models. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the DT determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their Interconnection-wide models and subsequently their planning cases. The DT considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The DT further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

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		To bookend these criteria for acceptable models, proposed Requirement R2 would also require any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The Unacceptable Models List includes models that NERC has identified over time as having known issues. While the DT initially proposed to foreclose the use of such models, the DT considered feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The DT believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns. The DT debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the DT ultimately decided to include this requirement in Requirement R2 as it relates to how entities respond to data specifications. The DT has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or

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		remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the DT has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for entities for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff are currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.
P124. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and		**Theme:** Nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies. (Uniform Modeling framework)

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dynamics studies. We acknowledge NERC's comment that user-defined models may be helpful for specific local reliability studies; however, the user-defined model cannot be used in place of nation-wide approved component models for regional analysis or interconnection-wide analysis because the user-defined model may cause non-convergence and other issues. However, NERC may allow the submission of user-defined models alongside the approved industry generic IBR model. Various entities do not accept user-defined models or only accept them for limited instances along with the open-source code which then allows internal model components to be viewed and modified. For example, PJM does not accept user-defined models and requires generic models for model verification in accordance with currently effective Reliability Standards MOD-026-1 and MOD-027-1. NYISO accepts a user-defined model in limited instances but requires either the open-source code (allowing anyone to access the internal model) or dynamic link library data and code files (compiled code that must be decompiled to view the internal model) that must be supplied for existing power flow software and in perpetuity."		The uniform modeling framework established in the proposed MOD-032 will focus on the use and representation of positive sequence phasor domain (PSPD) models in registered entity footprints and in Interconnection-wide models. Interconnection-wide modeling may be different from the models used in specialized studies dedicated to a particular technical objective. The ERO Unacceptable Models List applies to the models where NERC Reliability Standards require its use (generally for planning and operation models where multiple entities share information beyond their portion of the electric system, which includes Interconnection-wide models). Further guidance for interconnection applications can be found in the *NERC Dynamic Model Recommendations*. The DT considered introducing an approved model list for use in building cases specifically for Interconnection-wide analysis through Requirement R1 Part R1.2 of the proposed MOD-032, however, pre-defining a limited set of models that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To meet this directive, the DT modified Requirement R1 of MOD-032 by specifying the use of standard library "generic" models in Interconnection-wide cases while allowing the use of user-defined models. This provision was careful to address typically reported issues associated with user-defined models (UDMs) including non-convergence, by requiring that TP/PCs establish usability requirements for UDMs while incorporating an open, transparent process of identifying deficient models through the use of the "MOD-032 Supporting Documentation – Process for Updating the Unacceptable Models List Maintained by the ERO" and the "ERO Unacceptable Model list". Any TPs/PCs accepting UDMs shall provide

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		their UDM requirements to other PCs/TPs within the Interconnection upon request. The DT believes this approach balances the practical limitations of "generic models" raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop with the need for an improved uniform modeling framework. The combination of specifying the use of standard library component models approved and offered by software simulation tools, along with the ERO maintained Unacceptable Model List and its processes, will ensure that models used in interconnection wide analysis are robust enough while accuracy is not compromised to any level of detail deemed necessary. The introductions to this framework increase the data specifications requirements when user-defined models are used. TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P125. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models. One example of a way NERC could meet this directive would be to require an equivalent generic library model along with all submissions of user-defined models so that the generic library model can be used when combining	MOD-032 IRO-010 TOP-003	**Theme:** Nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build Interconnection-wide models. (Uniform Modeling framework /Req language) • Nation-wide approved components via generic library models are addressed via the development of a framework established in the proposed MOD-032-2 through improvements to Requirements R1, R2, and R3. The inclusion of ERO Unacceptable Models List, MOD-032 Supporting Document, and additional

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neighboring transmission system models and in interconnection-wide models."		requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. • The PC and TP are allowed to require provision of generic models, but if equipment-specific models satisfy usability criteria, and processes established through Requirements R1, R2, and R3 of the proposed MOD-032 standard, they are not prohibited. The framework explicitly allows for the submission of equivalent generic library models along with submissions of user-defined models which allows for the use of generic library models when combining neighboring transmission system models and Interconnection-wide models. • TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P141. "We also direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior. Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to	MOD-032 IRO-010 TOP-003	**Applicability**: GO • Nation-wide approved components via generic library models are addressed via the modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establishing an improved uniform modeling framework. This approach is aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop. • MOD-032, Attachment 1 was modified to specifically add that capabilities related to momentary cessation, tripping, and Ride-

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create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives. Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior). Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on		through, be reflected in the required model data for IBR and DER. • Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.

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the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives. Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models. Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System."		
P146. Accordingly, **we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to**	MOD-032 IRO-010 TOP-003	**Theme**: IBR-DER Model • As per the directive, the DT is requiring the modeling of aggregate DER through requirement R1 and Attachment 1. The currently available DER_A model is sufficient only for positive sequence phasor domain simulations. With the variety of other simulation domains (such as EMT and short circuit) necessary to study IBRs, mandating this model could prevent TPs or PCs from

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be able to perform respective system studies. For example, the new or modified Reliability Standards could require models of IBR-DERs (i.e., DER_A model) to adequately reflect the steady-state and dynamic aggregate resource performance in both a transmission area and across the interconnection. Additionally, estimated modeling data and parameters of IBR-DERs that in the aggregate (i.e., DER_A model) have a material impact on the Bulk-Power System could be used where measured and collected data is not available. We believe requiring the DER_A model will address NERC's request for entities to work collaboratively with the state regulators to identify, implement, and perform an effective model validation approach for IBR-DERs in the aggregate as opposed to requiring validated models of IBR-DER in the aggregate that can have a material impact on the reliable operation of the Bulk-Power System.		performing their studies. This further reinforces the DT's election to not require the use of the DER_A model, but rather a model that achieves specific performance criteria and conforms with MOD-032 edits in Attachment 1 and Requirement R1. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, not Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection (rather than mandating use of a defined set of models). Specific fidelity/accuracy evaluations are beyond the scope of MOD-032. • The DT considered referencing the DER_A model specifically, but refrained due to the rapidly evolving nature of models and concerns for the time required to update such a reference in a NERC Standard. Additionally, the DT is not specifying particular library models for other resources, so specifying a particular model for DER will invite challenges. Further, challenges with precisely defining and determining what a "successor model" is could potentially create more future reliability risks. The standard as currently written allows for additional future models of higher fidelity to be accommodated.
P157. We believe the development of new or modified Reliability Standards is an important corollary to NERC's ongoing effort to identify and register generator owners and operators of IBRs. Although NERC's registration changes will not at this time address IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, we believe APS's concerns	MOD-032 TOP-003 IRO-010	**Theme:** The responsible entity for IBR-DER data when there is no registered DP. Upon a decent amount of conversation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for

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regarding system-wide model validation is addressed in NERC's Reliability Guidelines and through the use of the EPRI DER Settings Database. We recognize that some distribution providers may not be able to provide a precise set of modeling data and parameters that accurately represent IBR-DERs in the aggregate. For these situations, NERC has provided a technical means to estimate in aggregating the needed IBR-DER modeling data and parameters (i.e., for the DER_A model) in the IBR-DER Data Collection Guideline. Further, NERC's 2021 Aggregate DER Model Verification Guideline provides transmission planners and planning coordinators with tools and techniques that can be adapted for their specific systems to verify that aggregate DER models (i.e., DER_A models) are a suitable representation of these resources in planning assessments. **Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models.**		collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." The use of the word "typical" is intentional to indicate the most likely entity based on the DT's broad understanding but allows flexibility per Requirement 1 for the PC/TPs to select a more appropriate entity or entities in their area based on regional or jurisdictional differences.
P161. "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal to provide additional specificity to explain coordination and keep up to date in a timely manner the verified data and models of	MOD-032 IRO-010 TOP-003	The DT modified MOD-032 to ensure it captures the uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements. Modifications in TOP-003 and IRO-010 are

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registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate in the system models. **Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model.** Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these resources in the system models. For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity		intended to promote consistency in models submitted for planning purposes and operations purposes. • A uniform modeling framework is established in the proposed MOD-032-2 through improvements to R1, R2, and R3. The inclusion of ERO Unacceptable Models List, MOD-032 Supporting Document, and additional requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. • The PC and TP are allowed to require provision of standard library models, but if user-written models satisfy usability criteria, and processes established through R1, R2, and R3 of the proposed MOD-032 standard, they are not prohibited. The framework explicitly allows for the submission of standard library models along with submission of user-written models which allows for the use of standard library models when combining neighboring transmission system models and Interconnection-wide models. • The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the MOD-032 standard. While the TO would be the typical entity for providing unregistered IBR data and the DP would be the typical entity to provide DER data (as noted in Attachment 1 of MOD-032), the DT modified the Requirement language to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2. Determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System, requires engineering judgment and is not something that would be appropriate to

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responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives. NERC may implement this directive by modifying Reliability Standards MOD-032-1 and MOD-033-2 or by developing new Reliability Standards to establish requirements mandating an annual process to coordinate, validate, and keep up-to-date the transmission planning, operations, and interconnection-wide models."		precisely specify in a reliability standard. Thus, Attachment 1 footnote 7 was added to explicitly allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard). To the extent modeling data is deemed necessary under IRO-010 and TOP-003, it should be consistent with modeling data provided for planning purposes. Therefore, the DT made changes to the IRO-010 and TOP-003 standards to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, not Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection (rather than mandating use of a defined set of models). Specific fidelity/accuracy evaluations are beyond the scope of MOD-032. MOD-032-1 already mandated a "schedule for submission of data at least once every 13 calendar months." This requirement is maintained in MOD-032-2. With regards to that part of the directive addressing a "registered model designee", NERC considered the directive and concluded that the present framework, with enhancements since 2023, presents an equally effective and efficient alternative to designating a model designee for

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		Interconnection-wide model building that is a registered entity. Further, this framework has distinct advantages over designating a responsible entity in that it maintains ongoing oversight, rather than compliance/audit-focused oversight. **Registered Modeling Designee:** The current MOD-032, Requirement R1, Part 1.1 requires the Planning Coordinator (PC) and each of its Transmission Planners (TPs) to identify the Entity responsible for each required item in Attachment 1. Requirement R3 requires notification from the PC or TP regarding technical concerns with the data submitted under Requirement R2. Additionally, a new Requirement R2, Part 2.2 has been added to require models provided under MOD-026 to be accepted by the Transmission Planner. This allows a more detailed model that has also been verified to receive a review and coordination in order to be accepted by the TP. These requirements allow for the coordination and model updates needed by registered entities. In addition, Requirement R4 requires each PC to make available models for its planning area under R2 to the Electric Reliability Organization (ERO) or its designee to support the creation of the Interconnection-wide cases. The ERO has designated Entities for each Interconnection, such as Texas Regional Entity, Western Electric Coordinating Council (WECC), and Eastern Interconnection Reliability Assessment Group (ERAG). Regarding the ERAG, there is an Eastern Interconnection Regional Entity

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		Agreement[1]. In this agreement, important connections to MOD-032 are acknowledged, like the following: • Oversight of the Multiregional Modeling Working Group[2] (MMWG, whose membership is comprised of one power flow representative and one dynamics representative from each of the Data Submitting Entities (comprised of Planning Coordinators or group of Planning Coordinators) and non-voting representatives as follows: one liaison representative each of the EI Regions and the ERAG Chair, a coordinator from each of the organizations that provides model development services to MMWG, and NERC and FERC staff liaisons. ○ The purpose of the MMWG is to coordinate, in a timely manner, the development of designated power flow and dynamics simulation base case models that realistically simulate steady state and dynamic bulk electric system behavior of the Eastern Interconnection. ○ To ensure cases and models are done in a consistent fashion, the MMWG holds three annual meetings along with conference calls as needed. The MMWG roster includes a FERC liaison who can attend all meetings. The group maintains a case building procedure manual[3] that is used by its members. The manual contains a set of data checks that are performed on the steady state and dynamic cases.

1 EI-Regional-Entity-Agmt-Final-Signed.pdf
2 ERAG-MMWG-Charter-2024.pdf
3 Microsoft Word - ERAG Base Case Release Procedure

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		• Oversight of the Acceptable Model Working Group (AMWG)[4], which is comprised of: (1) Planning Coordinators or group of Planning Coordinators who are responsible for the development and maintenance of an Eastern Interconnection dynamic acceptable model list, and (2) RE and NERC staff who are responsible for coordination and facilitation. ○ The group was formed in 2023 and recently published the first version of its acceptable model list which was posted to the public ERAG website[5]. As models are removed from the acceptable list, the group develops an industry communication to begin removing those models from the annual set of cases. ○ Oversight includes review of all process changes made to the AMWG procedures to ensure consistency with the NERC case quality metrics. • The ERO Enterprise Designation for MOD-032-1: NERC is designating the MOD-032-1 "Designated Entity: responsibilities to the Regional Entities to support NERC in fulfilling its obligations under Requirement R4 given their expertise in their respective geographic jurisdiction." The MOD-032 designees are contractually bound to carry out their duty for building the Interconnection-wide base cases.

[4] https://www.rfirst.org/wp-content/uploads/2023/10/ERAG_AcceptableModel_WorkingGroup_Charter.pdf

[5] www.erag.info

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		In addition, the DT has considered the following information provided by the MOD-032 Designee Group: **MOD-032 Designee Group:** The electric grid is evolving at an unprecedented pace, driven by the rapid integration of inverter-based resources (IBRs), changing load characteristics, and emerging technologies. As the system transforms, too must the models we use to study and understand its behavior. We recognize the growing challenge of obtaining and coordinating accurate dynamic models for IBRs, including securing the appropriate parameters needed to ensure that simulation results reflect real-world system performance. Addressing these modeling challenges is essential to maintaining the reliability and resilience of the bulk power system and requires close collaboration, and the MOD-032 designees along with PCs are committed to and holding data providers accountable for model coordination and model quality. The MOD-032 designees are committed to ensuring that the model quality is maintained and there is a mechanism in place for the PC/TP to gather the appropriate information from the Generator Owners (GO). NERC facilitates the designee group of Regional Entity staff who are responsible for designee activities. This group meets periodically to discuss case quality metrics and to improve the interconnection case-building process. A sub-team has been assembled to write a MOD-032 SAR to add authority for the Designee to enforce model quality. Overall, the FERC directive has been addressed through current and updated requirements/processes.

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P226. "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 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."	MOD-032 IRO-010 TOP-003	**Theme:** Sufficient timeframe. The DT felt that four years was an appropriate timeframe for the MOD-032, IRO-010, and TOP-003 implementation times. It is understood that based on what is required via MOD-032, industry would need two years to hold meetings with stakeholders to establish processes for collecting the needed models and data, and then an additional two years to update models based on the new requirements, etc. However, taking into consideration the FERC Order 901 implementation deadline of 2030, the DT settled on a three-year implementation time knowing that milestone 4 revisions still need to be implemented by 2030 and are dependent on the Milestone 3 implementation plan time. Three- year implementation plans were also selected for TOP-003 and IRO-010 to align potential new data requests under TOP-003 and IRO-010 with the expected data availability under MOD-032 processes.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Unacceptable Models List

Project 2022-02 Uniform Modeling Framework for IBR

August 2025

RELIABILITY | RESILIENCE | SECURITY






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Overview/Introduction

FERC issued Order No. 901 on October 23, 2023, directing "NERC to develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."

Proposed Reliability Standard MOD-032-2 addresses the reliability issue identified by FERC in Order No. 901 in a manner that considers advancements in user written models since the issuance of Order No. 901, perspectives of planning entities across North America, and the historical practice of the ERO, which has been to maintain a use of unacceptable models, rather than acceptable models, due to the practical difficulties of keeping an acceptable model library up to date in a timely manner.

Reliability Standard MOD-032-2 requires the Planning Coordinator and Transmission Planner to include specifications addressing the use of standard library models, user-written models meeting certain minimum usability requirements to minimize the risk of non-convergence, or both. To minimize the use of models with known deficiencies, Transmission Planners and Planning Coordinators must also include provisions to require any entity submitted on the Unacceptable Model List to include a technical rationale supporting its use.

The Unacceptable Models List identifies models that are generally considered not acceptable for purposes of model submissions under the MOD-032, TOP-003, and IRO-010 Reliability Standards due to identified issues with usability or accuracy impacting the ability to develop planning or operational horizon cases necessary to support analysis of the reliability of the interconnected transmission system. However, it is recognized that the use of such models may be appropriate in some cases, such as where there is no feasible means for procuring an alternative model that may better represent the behavior of legacy equipment. Any use of such models must include a technical rationale supporting its use.

Disclaimers

Interconnection-wide modeling requirements may differ from the requirements of specialized studies dedicated to a particular technical objective. Thus, models deemed acceptable for planning purposes may be deemed unacceptable by a receiving entity for certain operations applications.

Updates to the Unacceptable Models List

Refer to the Supporting Document section of MOD-032.

Chapter 1: Unacceptable Models List

Models that have been identified as unacceptable are listed in Table 1 below. Revisions to this list may be made in accordance with the process described in the Supporting Document section of the MOD-032 standard.

Table 1: Unacceptable Model List		
Known Unacceptable Model Name	**Model Description**	**Effective**
Renewable Energy Models		
WT3G1, WT3G2, wt3g	Generic Type 3 WTG Generator/Converter Model - Doubly-fed induction generator	Effective Date of MOD-032-2
WT4G1, WT4G2, wt4g	Generic Type 4 WTG Generator/Converter Model - Variable speed generator with full converter	Effective Date of MOD-032-2
WT3E1, wt3e	Generic Type 3 WTG Electrical Control Model	Effective Date of MOD-032-2
WT4E1, WT4E2, wt4e	Generic Type 4 WTG Electrical Control Model	Effective Date of MOD-032-2
WT3T1, wt3t	Generic Type 3 WTG Turbine Model	Effective Date of MOD-032-2
WT3P1, wt3p	Generic Type 3 WTG Pitch Control Model	Effective Date of MOD-032-2
WT12A1, wt1p, wt2p	Generic Type 1 and 2 WTG Pitch Control Model	Effective Date of MOD-032-2
WT4E1, wt4t	Generic Type 4 WTG Power Converter Model	Effective Date of MOD-032-2
wt4p	Generic Type 4 Pitch Control Model	Effective Date of MOD-032-2
REECB1, REECBU1, reec_b	Generic Phase 2 PV Electrical Controls Model	Effective Date of MOD-032-2
Machine Models		
GENSAL, gensal	Salient Pole Generator Model (IEEE Std 1110 §5.3.1 Model 2.1)	Effective Date of MOD-032-2
GENCLS, gencls	Classical Generator Model (IEEE Std 1110 §5.4.2)	Effective Date of MOD-032-2
GENTRA	Transient Level Generator Model	Effective Date of MOD-032-2
Excitation System Models		
texs	General Purpose Transformer Fed Excitation System	Effective Date of MOD-032-2
SEXS, sexs	Simplified Excitation System	Effective Date of MOD-032-2
EX2000	GE EX2000 Excitation System	Effective Date of MOD-032-2
Turbine-Governor Models		
lm2500	LM 2500 Aero-Derivative Gas Turbine Governor Model	Effective Date of MOD-032-2
Known Unacceptable Model Name	**Model Description**	**Effective**

Table 1: Unacceptable Model List		
lm6000	LM 6000 Aero-Derivative Gas Turbine Governor Model	Effective Date of MOD-032-2
URGS3T, gast	WECC Gas Turbine Governor Model	Effective Date of MOD-032-2
GAST	Gas Turbine-Governor Model	Effective Date of MOD-032-2
GAST2A	Gas Turbine-Governor Model	Effective Date of MOD-032-2
GASTWD	Gas turbine-governor	Effective Date of MOD-032-2
IEEEG2	1981 IEEE Type 2 General Approx. Linear Ideal Hydro Model	Effective Date of MOD-032-2
WESGOV	Westinghouse Digital Governor Model for Gas Turbines	Effective Date of MOD-032-2
Load Models		
motorc	Phasor Model of Single-Phase Air-Conditioner Compressor Motor	Effective Date of MOD-032-2

Chapter 2: Unacceptable Models Technical Rationale

Table 2 below provides the technical rationale for each unacceptable model included on the current Unacceptable Models List.

The purpose of this list of unacceptable models is to develop and maintain a repository of models deemed acceptable by the ERO and industry stakeholders for use in developing interconnection-wide models developed by the MOD-032 Designee. The NERC System Analysis and Modeling Subcommittee (SAMS) initially developed this list, and it is now maintained and updated by ERO staff in accordance with MOD-032 Supporting Document. This list seeks to bring together multiple sources of data to ensure uniformity in the use of models across Interconnections. While models may be deemed 'obsolete' or 'deprecated' due to known issues, these models are not removed from the software vendor libraries for various reasons. However, these models should not be used to represent specific facilities within Interconnection-wide models. For additional information about this list, please contact NERC staff at advancedsystemanalyticsmodeling@nerc.net with any questions.

Table 2: Unacceptable Model List

Known Unacceptable Model Name	Rationale For Inclusion
Renewable Energy Models	
WT3G1, WT3G2, wt3g	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT4G1, WT4G2, wt4g	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3E1, wt3e	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT4E1, WT4E2, wt4e	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3T1, wt3t	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3P1, wt3p	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT12A1, wt1p, wt2p	Unable to represent common Type 1 wind pitch control logic.
WT4E1, wt4t	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
wt4p	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
REECB1, REECBU1, reec_b	Inability to represent momentary cessation or other voltage dependent current logic common in the equipment the model was stated to represent.
Machine Models	

Table 2: Unacceptable Model List	
Known Unacceptable Model Name	**Rationale For Inclusion**
GENSAL, gensal	Uses simplifying approximations for saturation as additive terms over exponential or quadratic curves. Further, ignores the q-axis saturation completely.
GENCLS, gencls	Does not allow for representation of excitation system and turbine/speed governor models
GENTRA	Simplified model that ignores sub transient effects, leading to numerical instability problems.
Excitation System Models	
texs	Simplified, early generation model considered obsolete. Refer to IEEE Std 421.5
SEXS, sexs	Simplified, early generation model considered obsolete. Refer to IEEE Std 421.5
EX2000	Field current limiter latch in the model is unable to represent the field equipment for simulation in power system software. Replace with AC7B or ex21br
Turbine-Governor Models	
lm2500	No supporting documentation implemented in software, proprietary model with no added model support.
lm6000	No supporting documentation implemented in software, proprietary model with no added model support.
URGS3T, gast	Simple representation of steam turbine-governor system with insufficient model capability for modern digital controllers.
GAST	Simple representation of steam turbine-governor system with insufficient model capability for modern digital controllers.
GAST2A	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
GASTWD	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
IEEEG2	Model uses an oversimplified governor model applicable only to first swing stability. Deprecated with other hydro governor models.
WESGOV	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
Load Models	
motorc	Experimental load model. Should not be used for generation resources

Additional References

The references below are provided for further reading and information about the models above. These references are:

- "IEEE Guide for Synchronous Generator Modeling Practices and Applications in Power System Stability Analyses," IEEE Std 1110-2002.
- Undrill, J., "The gentpj model," November 19, 2007 (updated June 19, 2012).
- "IEEE Recommended Practice for Excitation System Models for Power System Stability Studies," IEEE Std 421.5-2005.
- "Computer Representation of Excitation Systems," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-87, No. 6, pp. 1460-1468, 1968 (Committee Report).
- "Excitation System Models for Power System Stability Studies," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 2, pp. 494-509, 1981 (Committee Report).

- IEEE Task Force on Overall Plant Response, "Dynamic Models for Steam and Hydro Turbines in Power System Studies", IEEE Trans. on PAS, Vol PAS-92, Nov-Dec 1973, pp. 1904-1915.
- Task Force on Turbine-Governor Modeling, "Dynamic Models for Turbine-Governors in Power System Studies," IEEE Technical Report, PES-TR1, Jan. 2013.
- WECC M&VWG, "Composite Load Model for Dynamic Simulations" Ver 1.0, June 12, 2012.
- WECC M&VWG, "WECC Wind Power Plant Dynamic Modeling Guide," November 2010.
- EPRI, "Specification of the Second Generation Generic Models for Wind Turbine Generators," September 20, 2013. and WECC M&VWG, "Generic Solar Photovoltaic System Dynamic Simulation Model Specification," September 2012.
- WECC, "Generic Static Var System Models for the Western Electricity Coordinating Council" April 18, 2011.
- W. I. Rowen, "Simplified Mathematical Representations of Heavy Duty Gas Turbines", ASME Paper 83-GT-63 and ASME Journal of Engineering for Power, October 1983, pages 865-869. [GAST2A reference]
- Periera, L. et al, "A New Thermal Governing Approach in the WECC," IEEE Transaction on Power System, Vol. 18, No. 2, pp. 819-829, May 2003.
- WECC M&VWG, "Cross-current Compensation Model Specification," August 2015.
- EPRI, "Simple Model Specification for Battery Energy Storage System," March 6, 2015.
- WECC M&VWG, "WECC Wind Power Plant Dynamic Modeling Guide," April 2014.
- WECC M&VWG, "WECC PV Power Plant Dynamic Modeling Guide," April 2014.
- EPRI, "Proposed Changes to the WECC WT3 Generic Model for Type 3 Wind Turbine Generators," September 27, 2013.
- EPRI, "Proposed Changes to the WECC WT4 Generic Model for Type 4 Wind Turbine Generators," January 23, 2013.
- Q. Wang, "GENQEC Generator Dynamic Model", July, 2019. https://www.wecc.org/Administrative/GENQEC%20Model%20Specification.pdf
- Q.Y. Wang, S. Wang, "A New High Accuracy Generator Dynamic Model", 2018 IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC).

Chapter 3: Sample Submission Form

This form is a sample to explain what is deemed a full application to change a model designation in the Unacceptable Models List.

Section 1: Submitting Entity Information			
Name of Person submitting			
Organization(s)			
Sector (if known)			
Telephone		Email	

Section 2: Model Identifying Information	
Model Name	
Alternative Model Name(s) as implemented in software	
Equipment Model is stated to represent	
Indicate desired Action	☐ Add model to the Unacceptable Models List ☐ Remove model from the Unacceptable Models List

Section 3: Technical Supporting Documentation and Description	
Description of model ability to meet small signal Disturbances	
Description of model ability to meet large signal Disturbances	
Please cite and link any industry approved documentation regarding this model's small and large signal disturbances	
Describe the technical document attachments that support the above questions	
Please identify any information in this application that may meet the criteria for Confidential Information, as defined in Section 1500 of the NERC Rules of Procedure	

Section 4: Process Tracking	
Date Submitted to ERO	
Model Status	☐ Submitted to the ERO ☐ Assigned ERO Review team ☐ Investigation and review by ERO and submitting entity ☐ Remanded by NERC RSTC (or its successor) ☐ Approved by the NERC RSTC (or its successor)
Date of Approval	
Date of Model Notice to Industry	

Attachments

If available, please include at least one report that uses Hardware-in-the-Loop, Software-in-the-Loop, or actual System response (e.g., in a commissioning test) to demonstrate the model's ability or inability to achieve its stated purpose. At least one attachment should detail the model's error boundaries to represent its stated equipment with the test description and procedure outlined in that report. Entities shall label any attachment that may meet the criteria for Confidential Information under NERC Rules of Procedure Section 1500, along with the basis for the designation (e.g., Confidential Business and Market Information, Critical Electric Infrastructure Information, etc.). If any of this information is not available to the supporting entity, please provide an explanation.

Chapter 4: Version History

Version	Date	Action	Change Tracking
1	August 2025	Draft 2 Posting for Project 2022-02	Initial Draft

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Formal Comment Period Open through September 10, 2025

Now Available

A 34-day formal comment period for **Project 2022-02 Uniform Modeling Framework for IBR**, is open through **8 p.m. Eastern, Wednesday, September 10, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and Information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- 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 **August 28 - September 10, 2025**.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 470-479-7538. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR 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:	2022-02 Uniform Modeling Framework for IBR | Draft 2
Comment Period Start Date:	8/8/2025
Comment Period End Date:	9/10/2025
Associated Ballots:	2022-02 Uniform Modeling Framework for IBR | Draft 1 Implementation Plan AB 2 OT 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 | Non-binding Poll AB 2 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 AB 2 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 | Non-binding Poll AB 2 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 AB 2 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 | Non-binding Poll AB 2 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 AB 2 ST

There were 68 sets of responses, including comments from approximately 153 different people from approximately 103 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed MOD-032-2 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

2. Do you agree with the proposed IRO-010-6 and TOP-003-8 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

3. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-6, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

4. Do you agree with the proposed ERO Unacceptable Models List? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

5. Provide any additional comments for the 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
Adrian Harris	Adrian Harris		MRO,RF,SERC	RTO/ISO Council Standard Review Committee	Elizabeth Davis	PJM	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Adrian Harris	MISO	2	RF
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Joshua Phillips	SPP	2	MRO
					Ali Miremadi	CAISO	2	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
					George Brown	Pattern Operators LP	5	MRO
					Amy Key	MidAmerican Energy	1	MRO

						Company (MEC)		
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
					Hayden Maples	Evergy	1,3,5,6	MRO
					Kirsten Rowley	MISO	2	MRO
					Andrew Coffelt	Kansas City Board of Public Utilities	1,3,5,6	MRO
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	1	NPCC	Con Edison	Dermot Smyth	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange & Rockland		NPCC
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,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	James Shultz	Hoosier Energy Electric Cooperative	1	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kelly Heims	Central Iowa Power Cooperative	1	MRO
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					DJ Stone	North Carolina Electric Membership Corporation	3,4,5	SERC
Black Hills Corporation	Josh Schumacher	6		Black Hills Corporation Segments 1, 3, 5, 6	Trevor Rombough	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
					Josh Schumacher	Black Hills Corporation	6	WECC
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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

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
Northeast Power Coordinating Council	Ruida Shu	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

Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	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
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
Emma Halilovic	Hydro One	1,3	NPCC
Philip Nichols	National Grid	1	NPCC
Emma Halilovic	Hydro One	1,3	NPCC

					Caver Powers	Utility Services	5	NPCC

1. Do you agree with the proposed MOD-032-2 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

The SDT's response to AEP's previous comments states that "Attachment 1 does not create obligations for entities to provide data, but specifies the data items that need to be covered by the PC/TP data reporting procedures and requirements." While this is true, a compliance obligation nonetheless remains on the PC/TP to document data reporting requirements that address or cover the items in Attachment 1. We maintain that the items as given in 7a and 10a of the Dynamics column are too all-encompassing for positive sequence modeling, particularly "momentary cessation" and "ride-through," so the recommendations made in our previously submitted comments remain the same. While there are provisions for representing voltage and frequency protection settings in positive sequence simulations, "momentary cessation, tripping, and ride-through" are too open-ended, and may not be able to be represented completely in positive sequence phasor domain simulations, and lack the clarity needed to be certain of compliance. AEP suggests the following be used instead:

7a. "In the absence of project specific data, include estimated, assumed, or typical voltage and frequency protection settings."

10a. "Include estimated, assumed, or typical aggregate voltage and frequency protection settings."

The SDT's response also stated that they "received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point" and that "this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc." While AEP appreciates the addition of footnote 7 of Attachment 1 Data Reporting Requirements and the flexibility it provides in allowing aggregate thresholds to be specified, it is difficult to envision GOs, BAs, and RPs as being potentially held responsible for DER aggregation modeling. As stated in our previous comments, FERC Order 2222 DER aggregators would seem to be well-positioned to coordinate with their constituent DERs, consolidate the necessary modeling and planning data, and meet compliance obligations. AEP recommends that consideration be given in pursuing FERC Order 2222 DER aggregators for this purpose.

AEP is concerned that R1.1 allows the PC and TP to determine the entity who is ultimately responsible to obtain each of the required items in Attachment 1. In effect, two Functional Entities are essentially given authority to decide who bears both the responsibility and ultimate risk of obtaining data from entities with no obligations to provide it. Our concern is if the assigned entity is one that neither owns nor operates the equipment, and this possibility is a contributor to our decision to vote negative on MOD-032.

Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy supports the incorporation of the following EEI comment:

…"EEI appreciates the inclusion of the Abeyance Language, however, the language could be clearer and less repetitive. The subjectivity of the language (e.g., sincere intent) should be removed because it places unnecessary compliance risk the functional entities responsible. To resolve our concerns, we offer the following edits in boldface for NERC consideration."

Duke Energy supports the incorporation of the following EEI edits with one additional time change (see strike-through):

"For a period of two [three] years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C of the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for **unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided**. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested."

Additionally, Duke Energy does not agree with the modifications to IRO-010-6 and TOP-003-8, specifically for requirement R1.5.3 (both standards). MOD-032 and MOD-26 require models, and the PC and TP are required to jointly develop the models without RC or TOP input. Multiple modeling tasks may be required with significant additional cost if all four entities (RC, PC, TP, and TOP) do not coordinate their modeling needs. Therefore, Duke Energy recommends adding RC and TOP coordination language to R1 requirement of MOD-032-2. (Reference: Q1 – NERC Project 2022-02 Comment Form, due 9/10/2025)

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

FirstEnergy offers the following concerns toward the scope of Unregistered IBRs related to inclusion of GO/GOP Category 2's definition in MOD-032-2.

Requirement R2.1. states "Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
R2.1. refers to IBRs that do not meet the BES Definition or Generator Owner Category 2 criteria. This requirement brings all IBRs into applicability of the standard regardless of size or interconnectivity.
Project 2024-01 passed on May 7, 2025, and adds "Category 2" non-BES IBRs to the Generator Owner definition in the NERC Glossary of Terms. Category 2 IBRs include generation facilities that meet or exceed 20 MVA and are interconnected at or above 60 kV. The intent of Project 2024-01 was to include IBRs that do not meet the BES Definition but have a material impact on the reliability of the BES. Including IBRs that do not have a material impact on the reliability of the BES does not contribute to the reliability of the BES and adds unnecessary work for registered Generator Owners.
The reliability standard itself should not define applicability to reliability standards. The BES Definition and Generator Owner category 2 criteria alone should define applicability.
In addition, entities that own IBRs that do not meet the BES Definition or Generator Owner Category 2 criteria may not be required to register as a

Generator Owner and therefore are not held to compliance with the reliability standards. This creates an unfair advantage.
FirstEnergy considers it a bad precedent to bring in generation facilities that do not meet the BES Definition or Generator Owner category 2 criteria.

For FirstEnergy offers the following 3rd bullet under R2.1:

"Data for an IBR that is not a DER and meets the criteria for Generator Owner registration under the NERC Glossary of Terms, including Category 2 IBRs as defined in Project 2024-01. Data for IBRs that do not meet these criteria may be requested only if the Planning Coordinator or Transmission Planner determines that such resources have a material impact on the reliability of the BES."

Likes 0	
Dislikes 0	

Response

Kelly Heims - Central Iowa Power Cooperative - 1

Answer	No
Document Name	

Comment

Central Iowa Power Cooperative supports the comments submitted by ACES.

Likes 0	
Dislikes 0	

Response

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6

Answer	No
Document Name	

Comment

We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.

Likes 0	
Dislikes 0	

Response

Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	

Comment

MH appreciates the SDT ‘s consideration of our comments in the previous revision of the draft standard. In general, we are OK with the changes made to Requirement R1 of MOD-032-2; however, we would like to propose some wording and format changes to improve the clarity, as indicated below.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. The type of dynamic models accepted:

standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);

user-defined models; or

both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted,

1.4.2.1. Usability requirements for any submitted user-defined models, including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.2. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	

Comment

We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison

Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
Attachment 1, Footnote 3 effectively requires that all DERs are modeled, despite Footnote 7 allowing the procedure developed per R1 to define aggregation thresholds for DERs. Footnote 3 should instead read "For purposes of this item, aggregate Demand at each bus under item 1 is the Demand aggregated at the bus after removing any offsets due to DERs modeled at that bus according to the data requirements and reporting procedures developed by the PC and TPs per R1."	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
LG&E/KU does not support the revisions to MOD-032 due to the introduction of ambiguous compliance scenarios that are likely to arise from the revisions. The modifications to Requirement R1 Part 1.1 requiring the Transmission Planner (TP) to identify the entity responsible for providing data for all items in Attachment 1: (1) exceeded the scope of changes necessary to address FERC Order 901 directives, (2) removed certainty for functional entities regarding their obligations, and (3) failed to address FERC's explicit directive "to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System." In regard to point 3, it should be noted that the revised MOD-032 standard not only hands off the assignment of a responsible entity to TPs, it also fails to require that such entities be "registered entities." The formerly described issues aside, the revisions to MOD-032 have the potential to put TPs in a spot where compliance with the standard is unclear. If a TP assigns an unregistered entity responsibility for providing DER data under Requirement R1 Part 1.1, and the unregistered entity fails to provide	

data (or estimated data), it is not clear who is in violation. The TP has correctly performed its job under Requirement R1 Part 1.1, but the unregistered entity is not subject to NERC standards The standard does not explicitly give the TP the right to provide its own estimate in these cases, nor does it say that the TP must assume the compliance burden on behalf of the unregistered entities. Ultimately, whether the TP supplements their own estimate or proceeds with no DER data, they venture into territory with unknown compliance repercussions.

Suggesting that TPs have other means to enforce compliance, such as stakeholder processes, is unsatisfactory. If this were always the case, compliance enforcement authorities would be redundant. LG&E/KU suggests that entities with sufficiently regulated processes that provide a reliable means of obtaining data from entities unregistered with NERC could be granted a regional variation of the standard. However, LG&E/KU maintains that the base NERC standard should be unambiguous on who provides data and that, in the case of DER connected to unregistered entities, NERC must select a registered, functional entity to bear the compliance burden. LG&E/KU suggests striking modifications to Requirement R1 Part 1.1 and all associated changes.

As an alternative means of addressing the FERC Order 901 directives, LG&E/KU suggests either (1) that the Transmission Owner (TO) bear the responsibility for the data associated with unregistered IBRs and DERs connected to unregistered distribution providers, or (2) the that TO bear the responsibility for data associated with unregistered IBRs, and that the TP be responsible only for estimating the data associated with DERs connected to unregistered distribution providers (i.e., direct estimation rather than mandatory attempted data collection and subsequent estimation). For both options, registered Distribution Providers (DPs) should bear the responsibility for data associated with DERs connected to their systems. These options (1) do not make edits outside of the necessary scope to address FERC Order 901 directives, (2) preserve clarity of compliance obligations for functional entities, and (3) address FERC's explicit directive to determine the appropriate registered entity for providing data for DERs connected to unregistered distribution providers.

Likes 0	
Dislikes 0	

Response

Isidoro Behar - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

As written, MOD-032-2, MOD-33, and MOD-026 reviews should be coordinated simultaneously to prevent potential conflicts and/or contradictory requirements. R2.1 should include a new measure that requires to provide evidence of estimation methods, assumptions, etc., for estimated data. As for the ERO Unacceptable Model List process, a decision-making window should be considered to not hamper case builds, and the process should coincide with interconnection case build cycles to streamline compliance.

Likes 0	
Dislikes 0	

Response

Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh

Answer	No
Document Name	

Comment
SRP Supports the comments submitted by AEP related to the use of an unacceptable model in R2. The submission of an unapproved model should not be acceptable. The focus should be on unregistered IBRs as mentioned by other participants.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	

Comment
The proposed MOD-032-2 modifications contain inconsistencies to the term used throughout the standard (i.e.: “entity responsible”. “functional entity”, and “entity”). The only term defined is “functional entity” within Footnote 2. The inconsistency in language is confusing. The references need to be consistent throughout the document. The standard needs to clearly state who is responsible for the evidence required for Compliance. If a single designation is not possible, make clear that the PC and TP shall designated who is responsible in R1.1 and be consistent with the language throughout the Standard. Requirement R2: Registered Tos and DP do not have the ability to provide or collect DER data from unregistered distribution providers. If this data is critical to the reliability of the BPS, then those unregistered distribution providers that have interconnecte4d DER that have a material impact on the BPS should be registered through NER registration criteria and added under 4.1 as a functional entity. We suggest the following language: Distribution Providers (DPs) shall provide aggregate Distributed Energy Resource (DER) data for DERs that have been identified by the responsible PC and TP to have a material impact on the BPS. The DP shall estimate the modeling data and parameters and include an explanation of the limitations of the availability of data, and explanation of the limitations of the data provided, and the method used for estimation. Requirement R3: There doesn’t seem to be a mechanism that a PC or TP can use to compel the model provider to submit a model or data that is acceptable. There is a 90-day response period that could end as an end-less loop if the TP doesn’t accept that the explanation where the technical basis doesn’t respond to the technical concerns.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	

Comment

NIPSCO supports the comments made by AEP.

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

The DT's Consideration of FERC Order 901 Directives said the following: " the DT did not know how to interpret **material affect** and therefore, left it up to the Planning Coordinator (PC) and each of its Transmission Planners (TP) to review, consider, and determine all unregistered IBR that would be materially impacted."

ACES asserts that the drafting team (DT) remains well within the scope of the directive in establishing a threshold to define "**material affect**" and suggests revising R2.1 as follows:

R2.1 – Each PC/TP shall, at their discretion, require R1 data from functional entities with 20 MVA or greater in total IBR-DER generation within their service territory.

R2.1.1 – For each functional entity with 20 MVA or greater in total IBR-DER generation within their service territory, the entity shall provide R1 data for individual IBR-DER units with a nameplate rating greater than or equal to 5 MVA.

Rationale for 20 MVA Threshold

Historical Precedent

- The 20 MVA threshold has historically served as a continent-wide bright-line criterion distinguishing facilities that materially affect Bulk Power System (BPS) reliability from those that do not.
- This threshold is further supported by its use in defining Category 2 GO/GOP IBRs.

Consistency Across Resource Types

- Fossil fuel generation units under 20 MVA are not required to provide this modeling data. Requiring non-BES IBR-DER data below this threshold would create an inconsistent and potentially inequitable standard.

Avoiding Regional Discrepancies

- Without a DT-defined threshold, PCs/TPs will inevitably apply varying criteria.
- Entities operating in multiple PC/TP areas could face inconsistent and burdensome reporting requirements.

Improved Data Quality and Model Accuracy

- Setting the threshold at 20 MVA total, with mandatory reporting for units ≥5 MVA, increases the likelihood of obtaining verifiable, high-quality data from functional entities.
- This approach reduces reliance on estimates for small units, resulting in more accurate models.
- Better models directly enhance BPS reliability.

ACES' member North Carolina's Electric Cooperatives shares the following in addition to the threshold advocated for by ACES: **"Without waiving any rights to assert jurisdiction overreach by NERC/FERC, and assuming for the sake of argument that authority exists: Each DP will coordinate with the RC/TP on projects < 5MVA as needed".**

Likes 0	
Dislikes 0	

Response

George Goddard - DTE Energy - 5

Answer	No
Document Name	

Comment

I still struggle with R2 2.1: "If the responsible entity, as identified in Requirement R1 Part 1.1, is unable to gather unregistered Inverter-based Resource (IBR)1 data or aggregate Distributed Energy Resource (DER) data, the responsible entity shall estimate the modeling data and parameters and include an explanation of the limitations of 1 As used in this standard, the phrase "unregistered IBR" refers to a Bulk-Power System connected IBR that does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. MOD-032-21 — Data for Power System Modeling and Analysis Initial Draft of MOD-032-2 April 2025 Page 6 of 25 the availability of data, an explanation of the limitations of any data provided, and the method used for estimation. " This creates a burden to the DP and the data may not be accurate enough for study purposes. Documenting the limitations will not address the data inaccuracies. A possible recommendation is is to provide a mechanism for the unregistered DER"s to become registered and therefore subjected to the same compliance obligations as registered DER's

Likes 0	
Dislikes 0	

Response

Greg Sorenson - ReliabilityFirst - 10 - RF

Answer	No
Document Name	

Comment

It does not appear that the language of the MOD-032 Supporting Document: Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) has considered the role of the Acceptable Models Working Group (AMWG) under Eastern Interconnection Reliability Assessment Group (ERAG) for building and maintaining the Eastern Interconnection models. But as part of the Standard, the Supporting Document likely supersedes the AMWG, and describes a more centralized process for the maintenance of the official Unacceptable Models List. It

does not appear that the language provided by the SDT aligns with the charter of the AMWG, unless the AMWG fits into the general description of the "ERO Staff" under items 2 and 3.

It should be noted that the MOD-032 designee and associated industry groups comprised of Planning Coordinators may have a modeling group that reviews the technical rationale for using models on the ERO Unacceptable Models List (in R3). While outside of the Standard, this should provide consensus on the validity associated with any technical rationale provided by data submitters.

The present draft of MOD-032 does not include any requirement to modify or replace models that are submitted and are on the ERO Unacceptable Models List and do not have a valid technical rationale. This could be accomplished through the addition of a sub-requirement (R3.3).

To facilitate a timely model building process it may be beneficial to reduce the time that the functional entity has to respond to a technical concern from the PC/TP from 90 to 30 days (R3.2.).

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF appreciates the SDT's consideration of comments in the previous ballot and the revisions to the standard made in response. However, the MRO NSRF still has the following concerns:

· The inconsistency of terms used throughout the standard (i.e.: "entity responsible ", "functional entity", "entity"). None of these terms are defined except "functional entity" in Footnote 2, and the inconsistency in language is confusing at best or even misleading, bringing ambiguity to a Reliability Standard. These references need to use a consistent term throughout the document. A Reliability Standard should clearly state who is responsible for the evidence required for Compliance. If a single designation is not possible, make it clear that the PC and TP shall designate who is responsible in R1.1 and be consistent with this language throughout the Standard.

· Requirement R2

While the MRO NSRF understands the need for improved modeling, Distribution Providers (DP) are the only entities who have information on DERs interconnected to their distribution systems. Registered entities (TO and DP) do not have the ability to provide or collect DER data from unregistered distribution providers. If this data is critical to the reliability of the BPS, then those unregistered distribution providers that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria and added under 4.1 as a Functional Entity. Moreover, DPs are to provide DER data that has a material impact on the BPS and subpart 2.1 should reflect this important consideration. To address our concerns, Distribution Providers (DPs) shall provide aggregate Distributed Energy Resource (DER) data for DERs that have been identified by the responsible PC and TP to have a material impact on the BPS. The DP shall estimate the modeling data and parameters and include an explanation of the limitations of the availability of data, an explanation of the limitations of any data provided, and the method used for estimation.

· Requirement R3 Concerns

There doesn't seem to be any mechanism whereby a PC or TP can compel the model provider to submit a model or data that is acceptable. There is a 90-day response period that potentially become an end-less loop if the TP doesn't accept the explanation where the technical basis doesn't respond to the technical concerns.

· Section C: Compliance Concerns

Potential Noncompliance (PNC) Abeyance Period

This does not provide any sense of comfort to those entities that are providing estimates to the best of their knowledge that they will not be held in non-compliance by an auditor. This section needs further clarification and not be subject to any Auditor's interpretation. Use of ambiguous words such as "Good Faith" are not auditable and are very subjective and therefore inappropriate in a Reliability Standard. Additionally, there is no guarantee that the Abeyance Period is 1) long enough for NERC to create a new Registered entity (DP-DER) which was the original intent of the Abeyance, 2) will even be approved as it is still a "Potential".

· Section E: Associated Documents

"MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)"

As currently presented, this document is NOT part of the Reliability Standard and is NOT enforceable as such and should be maintained as a separate standalone document with the ERO Unacceptable Models List. To keep it at the end of the Standard gives the impression that it is enforceable and part of the standard. However, we believe that the Model Criteria should be included in the affected Reliability Standards and only changed when those Standards are modified and as such it should be an enforceable part of the standard and NOT an Associated Document as listed in Section E.

The MRO NSRF recommends removing the title from Section E as an Associated Document and making it part of MOD-032. Replace the title: MOD-032 Supporting Document with Attachment 2.

· Footnote concerns

o Footnote 1:

The MRO NSRF does not agree with Footnote 1. Data required should be specified within each sub-bullet of each column for both steady-state and dynamics. Failure to do this creates potential confusion. This situation is further amplified by the inclusion of new registered entities such as category 2 GOs.

o Footnote 6:

TO and DP have no ability to collect or provide aggregate data for DERs that are not connected to their system. If DER data is needed from unregistered DP to preserve the reliability of the BPS, then those entities should be registered.

Likes 0	
Dislikes 0	

Response

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.

Likes 0	
Dislikes 0	

Response

Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

While we support the efforts of the drafting team for Draft 2 of MOD-032, there are concerns.

{C}· Use of varying phrases of “entity responsible “or “functional entity”, or “entity”. None of these terms are defined except “functional entity” in Footnote 2 and are confusing at best or misleading, bringing ambiguity to a Reliability Standard. This needs to be consistent throughout the document whichever term is used. A Reliability Standard should know who is responsible for what is required for Compliance. If not, make it clear that the PC and TP shall designate who is responsible in R1.1 and be consistent with this language throughout the Standard.

R1.1 The data listed in Attachment 1, including the entity responsible for each required item **as determined by the PC and TP.**

{C}· Alignment with Project 2024-01

ATC does not agree that MOD-032-2 has been sufficiently aligned with the Project 2024-01 Implementation Plan. As stated in the Project 2024-01 Implementation Plan that Category 2 GOs will be held responsible for GO requirements contained in MOD-032, yet the currently proposed MOD-032-2 Reliability Standard Applicability Section does not clearly identify those entities. While we recognize the proposed definition of GO includes both Category 1 & 2, ATC submits that that the following clarifying addition be added to 4.1.3 of the Applicability Section of MOD-032-2 (shown in **boldface**):

4.1.3 Generator Owner **- Category 1 and 2**

{C}· Requirement R2 Concerns

While it is understood that there is a need for improved modeling, Distribution Providers (DP) are the only entities who have information on DERs interconnected to their distribution systems. Registered entities (TO and DP) do not have the ability to provide or collect DER data from unregistered DP. If this data is critical to the reliability of the BPS, then unregistered DPs that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria and added as under 4.1 as a Functional Entity. Moreover, DPs are to provide DER data that has a material impact on the BPS and subpart 2.1 should reflect this important consideration. To address our concerns, **Distribution Providers (DPs) shall provide** aggregate Distributed Energy Resource (DER) data **for DERs that have been identified by the responsible PC and TP that have a material impact on the BPS**. **T**he **DP** shall estimate the modeling data and parameters and include an explanation of the limitations of the availability of data, an explanation of the limitations of any data provided, and the method used for estimation.

{C}· Requirement R3 Concerns

There doesn't seem to be any mechanism whereby a PC or TP can compel the model provider to submit a model or data that is acceptable. There is a 90-day response period that potentially could end as an end-less loop if the TP doesn't accept that the explanation where the technical basis doesn't respond to the technical concerns.

{C}· Attachment 1 Concerns

Steady State Concerns

Item 9 **–** TOs are entirely dependent on DPs and should therefore be removed from have direct responsibility for Aggregate DER data.

Dynamics Concerns

Item 10 – Consistent with previous comments, TOs should be removed from Item 10. They have no ability to provide aggregate DER data on any distribution system (registered or unregistered) because they do not own or interconnect those resources directly.

For DERs that are connected to UFLS Only DPs distribution providers, aggregated DER data connected to their distribution systems and information detailing DERs connected to UFLS schemes should be obtained from those registered entities. Additionally, UFLS and UVLS tripping capacity of DERs should be provided

The term "aggregate" should also be clarified for Item 10.

To address our concerns, we offer the following edits (in **boldface** and strikethrough):

10. Aggregate Distributed Energy Resource (DER) data [DP, TOs **UFLS DPs**]

b. Indication whether DERs is subject to tripping in conjunction with are part of any UFLS or UVLS schemes **and provide estimates of the affected aggregated tripping capacity on those schemes.**

{C}· Section C: Compliance Concerns

Potential Noncompliance (PNC) Abeyance Period

This does not provide any sense of comfort to those entities that are providing estimates to the best of their knowledge that they will not be held in non-compliance by an auditor. This section needs further clarification and not subject to any Auditor's interpretation. Use of ambiguous words such as Good Faith are not auditable and very subjective and inappropriate in a Reliability Standard. And there is no guarantee that the Abeyance Period is 1)

long enough for NERC to create a new Registered entity (DP-DER) which was the original intent of the Abeyance, 2) will even be approved as it is still a “Potential”.

{C}· Section E: Associated Documents

MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) in the standard. It is NOT part of the Reliability Standard and is NOT enforceable as such and should be maintained as a separate standalone document with the ERO Unacceptable Models List.

To keep it at the end of the Standard gives the impression that it is enforceable and part of the standard.

However, we believe that the Model Criteria should be included in the affected Reliability Standards and only changed when those Standards are modified and as such it should be an enforceable part of the standard and NOT an Associated Document as listed in Section E.

Recommendation is to remove the title from Section E as an Associated Document and make it part of MOD-032. Replace the title: *MOD-032 Supporting Document* with *Attachment 2*.

{C}· Footnote concerns

Footnote 1**:**

ATC does not agree with Footnote 1. Data required should be specified within each sub-bullet of each column for both steady-state and dynamics. Failure to do this creates potential confusion. This situation is further amplified by the inclusion of new registered entities such as category 2 GOs.

Footnote 6**:**

TO and DP have no ability to collect or provide aggregate data for DERs that are not connected to their system. If DER data is needed from unregistered DP to preserve the reliability of the BPS, then those entities should be registered.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	

Comment
While the drafting team has attempted to acknowledge the need for an aggregation threshold for DER that materially affects the reliability of the Bulk Power system and has added footnote 7 to attachment 1, footnote 3 contradicts this consideration by omitting a minimum threshold for which gross demand and DER aggregation would not need to be segregated, therefore inadvertently requiring a DP to have all information necessary to account for the DER and rendering provisions under requirement R2.1. useless. R2.1 focuses on aggregate DER data and not gross demand data which is impacted by DER data. DP's may have specific RERRA-jurisdictional regulatory limitations that prevent a DP's ability to parse gross demand from net demand due to BTMG. This is potentially avoided by setting an adequate minimum threshold for DER sizing determined to materially affect the reliability of the bulk power system, filtering out the smaller DER installations where separate metering is unavailable. We recommend the drafting team should expand the intent of footnote 7 to apply to gross vs net demand aggregations in footnote 3 or expand provisions in R2.1 to acknowledge aggregations of gross demand and DER resources, allowing for explanation of limitations in supporting data reporting for aggregate demand as currently defined in attachment 1.

Likes 0	
Dislikes 0	

Response

Wesley Yeomans - New York State Reliability Council - 10	
Answer	No
Document Name	

Comment
We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	

Comment
NextEra agrees with the modifications to MOD-032, however supports EEI's request to modify the Abeyance language of Section C, as provided below: For a period of two years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C **of** the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data **for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will**

pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA reiterates its previous comment regarding the TO not being the “appropriate registered entity to be responsible for providing estimations of unregistered load”. BPA asserts ‘actual’ data is the foundation for modeling of the bulk-power system. Without this crucial information, BPA believes estimating small/discrete unregistered IBRs is vague and doesn’t lend itself to creating models aligned with industry ‘best practice’ standards. BPA continues to recommend estimated base information come from the Regional Entity or require the submission of valid data from registered DER and IBR generators.

Additionally, as the DT mentioned in its response to industry comments “modifying NERC registration criteria is not a feasible option for addressing FERC 901 directives within the required timelines”, BPA believes a better, more ‘actual’ data driven alternative for future consideration, is requiring unregistered entities register under a new compliance registry type, such as “DP-DER”.

As this is a new area of focus, opportunity to learn, and refine, BPA agrees with the DT’s Technical Rationale that this standard is a great candidate for an abeyance period. BPA appreciates the inclusion of Section C, bullet 2, CMEP, Potential Noncompliance (PNC) Abeyance Period. This will allow industry to adapt, gain a better understanding, and make the necessary improvements.

In conclusion, BPA appreciates the urgency that NERC is responding to FERC directives but asserts NERC reliability standards should drive reliability. BPA believes grid modeling from ‘actual’ data leads to reliable outcomes.

Likes 0	
Dislikes 0	

Response

Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3

Answer	Yes
Document Name	

Comment

We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.

Likes 0	
Dislikes 0	

Response

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	

Comment

Black Hills Corporation does not object to the proposed changes made to MOD-032-2, however we do agree with EEI's suggested non-substantive changes for the drafting team to consider.

We agree with the concerns shared by EEI members that the lack of specificity regarding the delegation to the PC & TP to determine which entities are responsible for the data requirements in Attachment 1 could lead to some unforeseen difficulties in requesting the data, especially when non-registered entities are involved. The Abeyance Language helps for the short term but may not be the best long-term solution.

Black Hills Corporation agrees with EEI on removing bullet 4 from Section E "Process for Updating the Unacceptable Models List Maintained by the ERO" since this is already an attachment to MOD-032-2. This process document should be marked as Attachment 2 to clearly show separation between it and Attachment 1.

Black Hills Corporation also agrees with the changes to the Abeyance Language suggested by EEI to make it more clear. The suggested changes from EEI are in bold below:

For a period of two years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C **of** the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data **for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided.** Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Likes 0	
Dislikes 0	

Response

Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment

CEHE supports EEI comments as proposed.

Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
USV understands the FERC Order 901 directives and the need to approve the MOD-032 modifications as proposed. However, there are still concerns with the resources required for entities to fulfill the obligations, this is particularly important for smaller entities with limited budgets and time. USV believes that once the standard is implemented, the industry can gain a better understanding of how to achieve the same reliability gain without any additional burdens on entities.	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1	

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon supports the enhancements suggested in the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members.

EEI members continue to have concerns related to the decision to delegate to the PC and TP, in Requirement 1, the determination of which entities are responsible for the data requirements contained in Attachment 1. To clarify their concerns, this lack of specificity has the potential of creating unforeseen difficulties for both the PCs and TPs requesting the data and those entities identified as being responsible for supplying this data, particularly where non-registered entities are involved. And while the Abeyance language will likely be helpful at alleviating these problems in the short term, it is unclear whether this temporary solution will remedy this issue over the long term.

EEI suggests deleting from Section E (Associated Documents) bullet 4, “Process for Updating the Unacceptable Models List Maintained by the ERO” since this document is an attachment to MOD-032-2. Additionally, this process document should be marked and identified as Attachment 2, because as currently contained within MOD-032-2 there is no separation between Attachment 1 and this process document.

Finally, EEI appreciates the inclusion of the Abeyance Language, however, the language could be clearer and less repetitive**.** The subjectivity of the language (e.g., sincere intent) should be removed because it places unnecessary compliance risk on the functional entities responsible. To resolve our concerns, we offer the following suggested language for NERC consideration.

For a period of two years following the enforcement date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C of the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do

not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Likes 0	
Dislikes 0	

Response

Zahid Qayyum - New York Power Authority - 5

Answer	Yes
Document Name	

Comment

Regarding R1.4.2 - It is unclear whether this should be applied retroactively to the existing user written models. Its better that this be explicitly clarified within the standard itself .

Likes 0	
Dislikes 0	

Response

Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF

Answer	Yes
Document Name	

Comment

Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee

Answer	Yes
Document Name	2022-02_Unofficial_Comment_Form SRC.docx

Comment
In Attachment 1, page 15, the ISO/RTO Council (IRC) Standards Review Committee (SRC) requests additional clarity regarding the following statement: *"The joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify each entity's responsibility and data flow processes."* In the Consideration of Comments, could the drafting team please clarify how detailed the expectations are with respect to the data flow? Specifically, to what level of granularity should entities describe responsibilities and data exchanges within these processes?

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
ITC does not object to the proposed changes made to MOD-032-2 and appreciates the improvements made since Draft 1. However, we offer some input and non-substantive changes for DT consideration. ITC continues to have concerns related to the decision to delegate to the PC and TP, in Requirement 1, the determination of which entities are responsible for the data requirements contained in Attachment 1. To clarify our concern, this lack of specificity has the potential of creating unforeseen difficulties for both the PCs and TPs requesting the data and those entities identified as being responsible for supplying this data, particularly where non-registered entities are involved. And while the Abeyance language will likely be helpful at alleviating these problems in the short term, it is unclear how this will affect compliance on this issue over the long term.

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 EEI's comments.

Likes 0	

Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) aligns with 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 does not object to the proposed changes made to MOD-032-2 and appreciates the improvements made since Draft 1. However, we offer some non-substantive changes for DT consideration.

Some EEI members continue to have concerns related to the decision to delegate to the PC and TP, in Requirement 1, the determination of which entities are responsible for the data requirements contained in Attachment 1. This lack of specificity has the potential of creating unforeseen difficulties for both the PCs and TPs requesting the data and those entities identified as being responsible for supplying this data, particularly where non-registered entities are involved. And while the Abeyance language will likely be helpful at alleviating these problems in the short term, it is unclear whether this temporary solution will remedy this issue over the long term. Nevertheless, we look forward to working with NERC to resolve any issues that might arise surrounding this concern, should this issue manifest itself into legitimate problems.

EEI suggests deleting from Section E (Associated Documents) bullet 4, “Process for Updating the Unacceptable Models List Maintained by the ERO” since this document is an attachment to MOD-032-2. Additionally, this process document should be marked and identified as Attachment 2, because as currently contained within MOD-032-2 there is no separation between Attachment 1 and this process document.

Finally, EEI appreciates the inclusion of the Abeyance Language, however, the language could be clearer**.** The subjectivity of the language (e.g., sincere intent) should be removed because it places unnecessary compliance risk the functional entities responsible. To resolve our concerns, we offer the following edits in boldface for NERC consideration. (*STRIKETHROUGHS REMOVED*)

For a period of two years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C **of** the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data **for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the**

estimates provided. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.	
Likes 0	
Dislikes 0	
Response	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
SPP supports the comments provided by the IRC Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI does not object to the proposed changes made to MOD-032-2 and appreciates the improvements made since Draft 1. However, we offer some non-substantive changes for DT consideration.	

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Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathon Flores - Los Angeles Department of Water and Power - 1,3,5,6	
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 Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
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	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - TXNM Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 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	
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; John Nierenberg, 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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
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	

Document Name	

Comment

Southern Company does not object to the proposed changes made to MOD-032-2 and appreciates the drafting team's efforts in addressing concerns from Draft 1 of MOD-032-2. However, we offer some input and non-substantive changes for the DT consideration.

Requirement R1 Part 1.1 and Attachment 1 - While Southern Company appreciates the clarification provided in the technical rationale, Southern Company is concerned that not requiring the PC/TP to designate NERC registered functional entities in Requirement R1 could lead to a gap in enforceability. Southern Company recommends adding the word 'Functional' in front of entities to make it clear that the standard requires the PC/TP to designate registered functional entities. While Southern Company agrees that data can be sourced from both registered and unregistered entities, a registered entity must be specified as responsible in Requirement R1 for Requirement R2 to be fully enforceable.

Requirement R2 Part 2.2 – Southern Company appreciates the alignment of proposed standards MOD-032-2 and MOD-026-2. While the intent is clear in the technical rationale, Southern Company proposes the language below to better align with MOD-026-2.

"…, the functional entity shall provide the models **that its Transmission Planner received and provided a written notification that the model(s) and accompanying documentation are acceptable in accordance with** MOD-026, where such models are available."

Additionally, Southern Company supports EEI Comments.

Likes 0	
Dislikes 0	

Response

2. Do you agree with the proposed IRO-010-6 and TOP-003-8 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

As IRO-010-6, Requirement R1, Part 1.1 is currently drafted, it is unclear if the phrase “as deemed necessary by the Reliability Coordinator” at the end of Part 1.1 applies only to “identification of the entities responsible for responding to the specification” or if it applies to every category of data and information listed in Part 1.1. To address this ambiguity, ERCOT recommends that the phrase “as deemed necessary by the Reliability Coordinator” be moved from the end of Part 1.1 to the beginning of the list of data and information in Part 1.1, as follows:

A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments**, *as deemed necessary by the Reliability Coordinator*,** including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification.

A similar ambiguity exists in the current draft of TOP-003-8. Consequently, ERCOT recommends that corresponding modifications be made to Requirement R1, Part 1.1 and Requirement R2, Part 2.1 in TOP-003-8.

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; John Nierenberg, 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 does not support TOP-003 R1.5.3 because there is a lack of clarity and ambiguity in the Requirement language, as noted by other entities’ comments (specifically, BPA).

Likes 0	
Dislikes 0	

Response

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No

Document Name	
Comment	
MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The MRO NSRF would appreciate more clarity on “as applicable” as it is used in multiple sub-requirements throughout these two standards. Additionally, the MRO NSRF requests the changes to TOP and IRO be based upon requirements for using the data, potentially as envisioned in Milestone 4. As written, the use of planning models in the real-time operations, “as applicable”, seems to create a requirement the RC or BA gather data that may be of no value to these entities. Under the current standards, the information needed may be gathered by those entities if it is needed for reliability. If this change stands, it may require the RC and BA gather data for compliance purposes only and provide no real time value.	
Likes 0	
Dislikes 0	
Response	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
SPP supports the comments provided by the IRC Standards Review Committee	
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 the opinion of ACES that NERC registered entities should not be subjected to potential violations of multiple NERC Reliability Standards Requirements for a single action. In other words, we contend that by including requirements for model submissions in both MOD-032-2 and in a documented data specification(s), responsible entities will now be subject to a form of double jeopardy (i.e., claim preclusion). ACES recommends only requiring model submissions under MOD-032-2 and subsequently striking the following newly proposed requirement parts: IRO-010-6 Requirement R1 Part 1.5.3, TOP-003-8 Requirement R1 Part 1.5.3, and TOP-003-8 Requirement R2 Part 2.5.3.	
Likes 0	
Dislikes 0	
Response	
Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form SRC.docx
Comment	
The RC and BA are able to obtain the necessary model information to support real time assessments, real-time monitoring, and analysis within the current standards. Accordingly, we believe the proposed modification is unnecessary. Until such time as there is an obligation on the RC or BA to use the data in real time, then these changes are premature or unwarranted SRC is concerned about the phrasing with “as applicable” and the requirements to use planning models. This phrase is unclear for how it may be applied during an audit. Additional clarity could be added by clarifying at the discretion of the RC, these models may be used. If there are criteria envisioned it would be more appropriate to document those in the standard itself rather than leverage the planning models in the operational requirements.	
Likes 0	
Dislikes 0	
Response	

Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	
The focus should be on using data for real-time operations that do not gather data as mentioned by other participants. These standards (IRO-010/TOP-003) were created to have needed data that have been produced by other standards.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
Answer	No
Document Name	
Comment	
TAL believes the intent of 2.5.3 is well intended, but that this standard does not belong in TOP-003-8, R2. R2 is a BA standard. R2.5.3 seems to be a modeling standard. R2.5.3 seems redundant with respect to other modeling and commissioning standards being developed. TAL believes that in all practical sense, this must be accomplished in planning standards, which come into play during interconnection studies, model verification and validation processes and commissioning.	
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 responsiveness to our comments and the subsequent revisions to Requirements R1 Part 1.5.3 in IRO-010-6 and TOP-003-8 and Requirement R2 Part 2.5.3 in TOP-003-8, which now require the RC, BA and TOP functions to maintain in their data specs methods for entities to provide data and information, including “Requirements for model submissions to be consistent with the model submitted for planning purposes”. We noted in the Technical Rationale the stated objective of aligning the planning and operations models with reference to MOD-032-2, applicable on the Long-term Planning Time Horizon, as the typical driver for planning models submission. However, BC Hydro suggests that	

additional clarity in the context of the IRO-010 and TOP-003 standards, which are applicable in the Operations Planning Time Horizon, on modeling requirements possibly not in scope of the RC/BA/TOP.

If the intent is to mandate that entities identified in R1 Part 1.1 to submit system models consistent with those generated per MOD-032-3 (where possible as discussed in the Technical Rationale), BC Hydro suggests that the wording be revised to better reflect this. As drafted, it is not immediately clear which requirements the data spec documentation must include, and whether these requirements pertain to the models, models submission, or both.

Proposed wording for 1.5.3: Provisions for any model required for submission under the R1 data specification be consistent with the models created in accordance with MOD-032-2.

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Modeling data requirements should not be part of real-time data and information specification documents. Modeling data should remain in MOD standard.

Likes 0	
Dislikes 0	

Response

Kelly Heims - Central Iowa Power Cooperative - 1

Answer	No
Document Name	

Comment

Central Iowa Power Cooperative supports the comments submitted by ACES.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed modification contained in both IRO-010-6 and TOP-003-8.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	

We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.

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 supports the proposed IRO-010-6 and TOP-003-8 modifications.

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 modification contained in both IRO-010-6 and TOP-003-8.

Likes 0	
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1

Answer	Yes
Document Name	

Comment

Portland General Electric (PGE) aligns with EEI's 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 EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	

Response	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CEHE has no further comment.	
Likes 0	
Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
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 found no issues with updates to IRO-010-6 and TOP-003-8.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Per the NERC ROP, Section 300, reliability standards should use ‘clear language’: “Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance”. With that, BPA has concerns as to how the proposed TOP-003 R1.5.3 language “consistent with the model submitted for planning purposes, as applicable” will be interpreted by an auditor. BPA believes the current state estimation model and planning models differ in many cases. Where there are differences, those differences are usually driven by the unavailability of real time data for that model or the need to simplify it to obtain consistent solutions. In the technical rationale document, the drafting team claims the “as applicable” addresses that. Based on the seemingly open nature of R1.5.3, BPA has uncertainty that industry’s interpretation of “as applicable” will be the same as that of an auditor. BPA seeks clarity from the drafting team.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 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	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 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	
Scott Thompson - TXNM Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
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	

Isidoro Behar - Long Island Power Authority - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
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	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
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	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
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	

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

3. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-6, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

Regarding FirstEnergy's response to Q1 and Q2, FirstEnergy cannot determine the cost-effectiveness of achieving compliance toward this modification of MOD-032-2.

Likes 0	
Dislikes 0	

Response

Kelly Heims - Central Iowa Power Cooperative - 1

Answer	No
Document Name	

Comment

Central Iowa Power Cooperative supports the comments submitted by ACES.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE does not have comments.

Likes 0	
Dislikes 0	

Response	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	
Obtaining data from unregistered entities is not cost efficient. Having redundant tasks in multiple standards does not add to cost savings as mentioned by other participants.	
Likes 0	
Dislikes 0	
Response	
Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form SRC.docx
Comment	
TOP-003 and IRO-010 Requirements to gather data that is not needed or utilized by the RC or BA become an administrative burden to track and assess. Other expenses to store the unnecessary data highlight the ineffectiveness of costs.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	

Comment
TOP-003 and IRO-010 Requirements to gather data that is not needed or utilized by the RC or BA become an administrative burden to track and assess. Other expenses to store the unnecessary data highlight the ineffectiveness of costs.

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
ACES does not believe the proposed modifications to MOD-032-2 represent the most cost-effective means of addressing FERC Directive 901. ACES asserts that the DT remains well within the scope of the directive in establishing a threshold to define “material affect.” By proactively setting a threshold of 20 MVA or greater in aggregate and requiring mandatory reporting for inverter-based resource - distributed energy resources (IBR-DER) with individual nameplate ratings of 5 MVA or greater, the DT can satisfy the intent of the Standard Authorization Request (SAR) while enabling a more economically viable implementation for industry stakeholders. This approach allows entities to provide more meaningful and actionable data to the Planning Coordinator (PC) and Transmission Planner (TP), without incurring the significant compliance, legal, and accounting burdens associated with parsing and aggregating distribution-level interconnection agreements for small-scale IBR-DER units. Distribution providers would be able to leverage existing billing and metering systems to determine aggregate IBR-DER values and assess applicability under MOD-032-2 Requirement R2.1. This methodology is expected to offer a more practical and cost-effective path to compliance with FERC Directive 901. Furthermore, the resulting data provided to the PC/TP would likely be of higher quality, as individual nameplate data for IBR-DER units rated at or above 5 MVA is more readily obtainable and verifiable. This targeted reporting would yield more reliable data than estimates derived from significantly smaller IBR-DER units. Finally, this approach would reduce the volume of data sets requiring manual review and integration by the PC/TP, thereby lowering resource demands and improving overall cost efficiency.

Likes 0	
Dislikes 0	

Response

Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2

Answer	No
Document Name	

Comment

SPP supports the comments provided by the IRC Standards Review Committee

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 MOD-032, there will be an administrative burden due to the need to:

· Develop a methodology and process for the estimation process for data that is not available to the TO. This would not be a one-time effort but year over year as DER increases.

· Increased outreach to other entities such as registered DPs for their best estimate on the modeling.

· There will be a need to increase personnel to do the work that is already a tight market for applicable employees.

Likes 0	
Dislikes 0	

Response

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.

Likes 0	
Dislikes 0	

Response

Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	
Comment	
We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
For MOD-032, this will be an administrative burden due to the need to: {C}· Develop a methodology and process for the estimation process for data that is not available to the TO. This would not be a one-time effort but year over year as DER increases. {C}· Increased outreach to other entities such as registered DPs for their best estimate on the modeling. {C}· There will be a need to increase personnel to do the work that is already a tight market for applicable employees. There are no foreseen issues with IRO-010-6 or TOP-003-8.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
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	
Southern Company agrees the modifications for the proposed reliability standards address the scope of the SAR in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathon Flores - Los Angeles Department of Water and Power - 1,3,5,6	
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	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
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	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
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	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
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	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - TXNM Energy - 3	
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	
Ben Hammer - Western Area Power Administration - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Goddard - DTE Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
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	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, 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	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
No comment on cost effectiveness as Duke Energy’s focus is on reliability of the BES.	

Likes 0	
Dislikes 0	
Response	
Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE has no comment.	
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 will not comment on the cost effectiveness of the project.
Likes 0	
Dislikes 0	
Response
Donna Wood - Tri-State G and T Association, Inc. - 1
Answer	
Document Name	
Comment
N/A
Likes 0	
Dislikes 0	
Response

4. Do you agree with the proposed ERO Unacceptable Models List? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	No
Document Name	

Comment

NIPSCO does not believe that models on the unapproved list should be allowed to be used, even if technical justification is provided for doing so. There are legitimate reasons why these models should not be used, so a path for their potential inclusion should not be provided.

Likes 0	
Dislikes 0	

Response

Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh

Answer	No
Document Name	

Comment

Transmission Planners cannot submit models to the regional case build process that are not approved models. By allowing this, we will create a very costly and unproductive loop where DER models that are unacceptable keep getting sent back from the TP to the DP until they are acceptable. A standalone methodology would be better as mentioned by other participants.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

The act of renaming is creating a new list, not just replacing the old, acceptable model list. The ERO Unacceptable Models List does not have industry consensus and was not established through the standards process. TVA does not believe it should be referenced in a compliance standard. In its place, TVA recommends specifications for standard models (where appropriate and available), user-written models (where appropriate and with adequate documentation), and other models (when no alternative is available and requiring justification for use).

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not believe that models on the unapproved list should be allowed to be used, even if technical justification is provided for doing so. There are legitimate reasons why these models should not be used, so a path for their potential inclusion should not be provided.	
Likes 0	
Dislikes 0	
Response	
Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form SRC.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI supports the ERO's Unacceptable Model List.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
It does not appear that the language of the MOD-032 Supporting Document: Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) has considered the role of the AMWG under ERAG for building and maintaining the Eastern Interconnection models. I believe this document is more formal, and describes a more centralized process for the maintenance of the official Unacceptable Models List. It does not appear that the language provided by the SDT aligns with the charter of the AMWG, unless the AMWG fits into the general description of the "ERO Staff" under items 2 and 3.	
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 supports the ERO’s Unacceptable Model List.	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) aligns with 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 supports the ERO’s Unacceptable Model List.	
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 EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
USV agrees with the ERO Unacceptable Model List but requests that the reason for models being unacceptable be made public to provide clarity on Requirement R2.3.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
CEHE has no further comment.	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with the proposed ERO Unacceptable Models List.	
Likes 0	
Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
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	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Wesley Yeomans - New York State Reliability Council - 10	
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	
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; John Nierenberg, 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	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
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	
Brittany Millard - Lincoln Electric System - 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	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
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	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
George Goddard - DTE Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 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	

Ben Hammer - Western Area Power Administration - 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	
Scott Thompson - TXNM Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1	
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	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
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	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
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	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kelly Heims - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathon Flores - Los Angeles Department of Water and Power - 1,3,5,6	
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	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Provide any additional comments for the drafting team to consider, if desired.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP recommends that the Attachment “Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)” be removed from the MOD-032 standard, and added instead to the ERO Unacceptable Models List document.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
We appreciate the time and effort put in by the Drafting Team on this project and commend them for finding the best resolution for addressing the FERC 901 directive.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy believes MOD-032-2 R2.2 creates Requirement duplication by providing models already outlined and required in NERC MOD-026. The duplication creates the potential for non-compliance in two separate Standards, while also introducing overlapping documentation and reporting and possibly conflicting deadlines. Because MOD-032-2 R2.2 results in increased risk of Non-Compliance for the applicable entities, Duke Energy recommends R2.2 be deleted from the Standard.	
Likes 0	

Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy offers no additional comments.	
Likes 0	
Dislikes 0	
Response	
Kelly Heims - Central Iowa Power Cooperative - 1	
Answer	
Document Name	
Comment	
Central Iowa Power Cooperative supports the comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
TVA appreciates the efforts by the standard draft team. Regarding Attachment 1 Dynamics 10.b, this data could be difficult to accurately model for situations where the DP will often reconfigure their systems and move DERs between feeders. TVA recommends removing 10.b.	
Likes 0	
Dislikes 0	
Response	

Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	
Document Name	
Comment	
We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	
Document Name	
Comment	
We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	
Document Name	
Comment	
We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.	

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison

Answer	
Document Name	

Comment

We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1

Answer	
Document Name	

Comment

No additional comments

Likes 0	
Dislikes 0	

Response

Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	
Response	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE supports EEI comments as proposed.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource suggests defining or modifying the phrase “standard library models” in MOD-032 R1.4.1 to make it less application-specific as this phrase has no set meaning in some software.	

Eversource suggests the removal of Footnote 5 from Attachment 1 of MOD-032. This phrase provides little to no value and only provides speculation whereas Requirement R1.1 already defines a mechanism to assign ownership. In some regions, these data points may not be provided by the TO, but the footnote seems to imply that it should.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
The 2022-02 Technical Rationale (TR) in its IRO-010-6 and TOP-003-8 section (page 14) seems to indicate that modifications were made to “add reference to MOD-032”, however the only reference to MOD-032 has been added in the 2022-02 TR via the clarification on the intent behind the revised R1 Part 1.5.3 (and R2 Part 2.5.3 for TOP-003 only). Please clarify if the intention is to add a MOD-032 reference to Standards as well.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
The Reliability Standards Committee (RSC) of NPCC supports the proposed draft standard.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
Answer	
Document Name	

Comment
To reiterate, TAL believes the intent of 2.5.3 is well intended, but that this standard does not belong in TOP-003-8, R2. R2 is a BA standard. R2.5.3 seems to be a modeling standard. R2.5.3 seems redundant with respect to other modeling and commissioning standards being developed. TAL believes that in all practical sense, this must be accomplished in planning standards, which come into play during interconnection studies, model verification and validation processes and commissioning.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	

Comment
None

Likes 0	
Dislikes 0	

Response

Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF	
Answer	
Document Name	

Comment
Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) supports EEI’s comments on the revisions.

Likes 0	
Dislikes 0	

Response

Scott Thompson - TXNM Energy - 3	
Answer	
Document Name	

Comment	
Regional Entities may or may not have a list of acceptable and unacceptable models, how does the STD take into account certain unaceptable models vs acceptable per RE?	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	Project 2022-02 _ EEI Final Draft Comments _ MOD-032 IRO-10 TOP-003 Draft 2_ Rev. 0i _ 9_05_2025.docx
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 5	
Answer	
Document Name	
Comment	
Support Western Power Pool Comments	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	

The currently proposed MOD-032-2 Standard does not clearly identify which generations assets the standard is applicable to. We suggest that the following clarifying addition be added to 4.1.3 of the Applicability section of MOD-032-2

4.1.3 Generator Owner – Category 1 and 2

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

No additional comments.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

NIPSCO recommends that the Attachment “Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)” be removed from the MOD-032 standard, and added instead to the ERO Unacceptable Models List document.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

Thank you for the opportunity to share comments and suggestions. ACES realizes this has been a huge undertaking and we appreciate all the time and effort the DT has put into executing the FERC 901 Directive under such a short timeframe.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	2022-02_Unofficial_Comment_Form_Additional_Posting_NSRF v9.10.2025.docx

Comment

The MRO NSRF encourages clear and consistent identification of which generation assets standards are applicable to. The currently proposed MOD-032-2 Reliability Standard Applicability Section does not clearly identify those entities. While we recognize the proposed definition of GO includes both Category 1 & 2, the MRO NSRF proposes that the following be added to 4.1.3 of the Applicability Section of MOD-032-2 (shown in boldface):

4.1.3 Generator Owner - **Category 1 and 2**

Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	
Document Name	

Comment

R1.5.3 should be removed from TOP-003-8. Model submissions don’t belong in the data spec.

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

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	

Comment
MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.

Likes 0	
Dislikes 0	

Response

Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	

Comment
We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	

Comment

DP’s likely do not have in-house expertise available to comply with providing dynamic models of aggregated DER resources; even estimated modeling when certified modeling is unavailable due to regulatory limitations. NERC and the drafting team should consider resource availability of the consultants who will be required to support DP’s in the new compliance obligation as implementation plans are determined.

Likes 0	
Dislikes 0	

Response

Wesley Yeomans - New York State Reliability Council - 10

Answer	
Document Name	

Comment

We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO’s system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2022-02 Uniform Modeling Framework for IBR | Draft 2
Comment Period Start Date:	8/8/2025
Comment Period End Date:	9/10/2025
Associated Ballot(s):	2022-02 Uniform Modeling Framework for IBR | Draft 1 Implementation Plan AB 2 OT 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 | Non-binding Poll AB 2 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 AB 2 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 | Non-binding Poll AB 2 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 AB 2 ST 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 | Non-binding Poll AB 2 NB 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 AB 2 ST

There were 68 sets of responses, including comments from approximately 153 different people from approximately 103 companies representing 8 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 proposed MOD-032-2 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

2. Do you agree with the proposed IRO-010-6 and TOP-003-8 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.

3. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-6, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.

4. Do you agree with the proposed ERO Unacceptable Models List? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.

5. Provide any additional comments for the 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
Adrian Harris	Adrian Harris		MRO,RF,SERC	RTO/ISO Council Standard Review Committee	Elizabeth Davis	PJM	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Adrian Harris	MISO	2	RF
					Helen Lainis	Independent Electricity System Operator	2	NPCC
					Joshua Phillips	SPP	2	MRO
					Ali Miremadi	CAISO	2	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
George Brown	Pattern Operators LP	5	MRO
Amy Key	MidAmerican Energy Company (MEC)	1	MRO
Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
Michael Ayotte	ITC Holdings	1	MRO
Angela Wheat	Southwestern Power Administration	1	MRO
Joshua Phillips	Southwest Power Pool	2	MRO
Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO

					Hayden Maples	Evergy	1,3,5,6	MRO
					Kirsten Rowley	MISO	2	MRO
					Andrew Coffelt	Kansas City Board of Public Utilities	1,3,5,6	MRO
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	1	NPCC	Con Edison	Dermot Smyth	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange & Rockland		NPCC
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,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	James Shultz	Hoosier Energy Electric Cooperative	1	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kelly Heims	Central Iowa Power Cooperative	1	MRO
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					DJ Stone	North Carolina Electric Membership Corporation	3,4,5	SERC
Black Hills Corporation	Josh Schumacher	6		Black Hills Corporation Segments 1, 3, 5, 6	Trevor Rombough	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC

					Josh Schumacher	Black Hills Corporation	6	WECC
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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
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 -	3	SERC

						Alabama Power Company		
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	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
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	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

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
Emma Halilovic	Hydro One	1,3	NPCC
Philip Nichols	National Grid	1	NPCC
Emma Halilovic	Hydro One	1,3	NPCC
Caver Powers	Utility Services	5	NPCC

1. Do you agree with the proposed MOD-032-2 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

The SDT's response to AEP's previous comments states that "Attachment 1 does not create obligations for entities to provide data, but specifies the data items that need to be covered by the PC/TP data reporting procedures and requirements." While this is true, a compliance obligation nonetheless remains on the PC/TP to document data reporting requirements that address or cover the items in Attachment 1. We maintain that the items as given in 7a and 10a of the Dynamics column are too all-encompassing for positive sequence modeling, particularly "momentary cessation" and "ride-through," so the recommendations made in our previously submitted comments remain the same. While there are provisions for representing voltage and frequency protection settings in positive sequence simulations, "momentary cessation, tripping, and ride-through" are too open-ended, and may not be able to be represented completely in positive sequence phasor domain simulations, and lack the clarity needed to be certain of compliance. AEP suggests the following be used instead:

7a. "In the absence of project specific data, include estimated, assumed, or typical voltage and frequency protection settings."

10a. "Include estimated, assumed, or typical aggregate voltage and frequency protection settings."

The SDT's response also stated that they "received an overwhelming response from industry stating that there are different functional entities who could collect and provide data for DER where there is no associated registered DP between the DER connection point" and that "this could be the Transmission Owner, Distribution Provider, Generator Owner, Balancing Authority, Resource Planner, etc." While AEP appreciates the addition of footnote 7 of Attachment 1 Data Reporting Requirements and the flexibility it provides in allowing aggregate thresholds to be specified, it is difficult to envision GOs, BAs, and RPs as being potentially held responsible for DER aggregation modeling. As stated in our previous comments, FERC Order 2222 DER aggregators would seem to be well-positioned to coordinate with their constituent DERs, consolidate the necessary modeling and planning data, and meet compliance obligations. AEP recommends that consideration be given in pursuing FERC Order 2222 DER aggregators for this purpose.

AEP is concerned that R1.1 allows the PC and TP to determine the entity who is ultimately responsible to obtain each of the required items in Attachment 1. In effect, two Functional Entities are essentially given authority to decide who bears both the responsibility and ultimate risk of obtaining data from entities with no obligations to provide it. Our concern is if the assigned entity is one that neither owns nor operates the equipment, and this possibility is a contributor to our decision to vote negative on MOD-032.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC No. 901 directives (p141) specifically identify representation of "momentary cessation, tripping, and ride-through". To the extent such information is not available or cannot be adequately represented, Requirement R2 allows for data estimation along with an explanation of data limitations. The PC/TP should be able to develop data procedures that allow the data to be obtained from the best and most reliable sources available. The DT believes that this is best determined at the PC/TP level rather than dictated by NERC in MOD-032. The DT does not anticipate PCs and TPs requiring data from unregistered entities without some level of assurance (local authority, etc.) that those entities are the best and most reliable sources of information. The fact is that industry largely depends on data from entities that are not registered under NERC (OEMs, vendors, consultants, etc.) and it could be detrimental to reliability and model fidelity to obligate the PC/TP to only obtain data from NERC-registered entities. The drafting team proposed this flexibility (which does, in fact, allow the PC/TP to specify data from FERC Order 2222 DER Aggregators as suggested, if deemed feasible and appropriate) as an effective and efficient alternative to specifying a NERC-registered entity who would be obligated to provide such data for all scenarios that would be aligned with a more literal interpretation of the FERC directives.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports the incorporation of the following EEI comment:	

…"EEI appreciates the inclusion of the Abeyance Language, however, the language could be clearer and less repetitive. The subjectivity of the language (e.g., sincere intent) should be removed because it places unnecessary compliance risk the functional entities responsible. To resolve our concerns, we offer the following edits in boldface for NERC consideration."

Duke Energy supports the incorporation of the following EEI edits with one additional time change (see strike-through):

"For a period of two [three] years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C of the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for **unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided**. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested."

Additionally, Duke Energy does not agree with the modifications to IRO-010-6 and TOP-003-8, specifically for requirement R1.5.3 (both standards). MOD-032 and MOD-26 require models, and the PC and TP are required to jointly develop the models without RC or TOP input. Multiple modeling tasks may be required with significant additional cost if all four entities (RC, PC, TP, and TOP) do not coordinate their modeling needs. Therefore, Duke Energy recommends adding RC and TOP coordination language to R1 requirement of MOD-032-2. (Reference: Q1 – NERC Project 2022-02 Comment Form, due 9/10/2025)

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Thank you for your comments. Please see the DT's response to EEI.

Additionally, Abeyance language is drafted by NERC Compliance. Two years is appropriate to feed into any changes needed for MOD-032-2. This also is in sync with Requirement R2, which based on the implementation plan, would really give three years total.

Please see the updated IRO and TOP language. IRO and TOP language allows flexibility and the link to MOD-026 allows that connection. This points back to FERC Order 901 on accuracy.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy offers the following concerns toward the scope of Unregistered IBRs related to inclusion of GO/GOP Category 2's definition in MOD-032-2.

Requirement R2.1. states "Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
R2.1. refers to IBRs that do not meet the BES Definition or Generator Owner Category 2 criteria. This requirement brings all IBRs into applicability of the standard regardless of size or interconnectivity.
Project 2024-01 passed on May 7, 2025, and adds "Category 2" non-BES IBRs to the Generator Owner definition in the NERC Glossary of Terms. Category 2 IBRs include generation facilities that meet or exceed 20 MVA and are interconnected at or above 60 kV. The intent of Project 2024-01 was to include IBRs that do not meet the BES Definition but have a material impact on the reliability of the BES. Including IBRs that do not have a material impact on the reliability of the BES does not contribute to the reliability of the BES and adds unnecessary work for registered Generator Owners.
The reliability standard itself should not define applicability to reliability standards. The BES Definition and Generator Owner category 2 criteria alone should define applicability.
In addition, entities that own IBRs that do not meet the BES Definition or Generator Owner Category 2 criteria may not be required to register as a Generator Owner and therefore are not held to compliance with the reliability standards. This creates an unfair advantage.
FirstEnergy considers it a bad precedent to bring in generation facilities that do not meet the BES Definition or Generator Owner category 2 criteria.

For FirstEnergy offers the following 3rd bullet under R2.1:

"Data for an IBR that is not a DER and meets the criteria for Generator Owner registration under the NERC Glossary of Terms, including Category 2 IBRs as defined in Project 2024-01. Data for IBRs that do not meet these criteria may be requested only if the Planning Coordinator or Transmission Planner determines that such resources have a material impact on the reliability of the BES."

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. FERC Order 901 is intended to bring in all IBR, including DER. The DT drafted MOD-032 to include all IBR, including DER. With regards to material impact, that is engineering judgement. 901 focuses on BPS versus BES.	
Kelly Heims - Central Iowa Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Central Iowa Power Cooperative supports the comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	
Please see the DTs response to ACES.	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	

We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Estimation is only allowed in areas where unregistered DER data cannot be collected. This is for the typical entity, which would be the Distribution Provider and Transmission Owner. Requirement R2 Part 2.1 is an "if" statement. If you already have the data, then you would not need to complete 2.1. See FERC Order No. 901 P 104.	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

MH appreciates the SDT ‘s consideration of our comments in the previous revision of the draft standard. In general, we are OK with the changes made to Requirement R1 of MOD-032-2; however, we would like to propose some wording and format changes to improve the clarity, as indicated below.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. The type of dynamic models accepted:

standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);

user-defined models; or

both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted,

1.4.2.1. Usability requirements for any submitted user-defined models, including, at a minimum, requirements to provide model documentation and instructions for model set up and use. **1.4.2.2.** Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Majority of comments did not share similar concerns, and after review, the DT determined to leave the current MOD-032 R1 language as drafted.	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Estimation is only allowed in areas where unregistered DER data cannot be collected. This is for the typical entity, which would be the Distribution Provider and Transmission Owner. Requirement R2 Part 2.1 is an "if" statement. If you already have the data, then you would not need to complete 2.1. See FERC Order No. 901 P 104.	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	

Answer	No
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Estimation is only allowed in areas where unregistered DER data cannot be collected. This is for the typical entity, which would be the Distribution Provider and Transmission Owner. Requirement R2 Part 2.1 is an "if" statement. If you already have the data, then you would not need to complete 2.1. See FERC Order No. 901 P 104.	
Brian Lindsey - Entergy - 1	
Answer	No
Document Name	
Comment	
Attachment 1, Footnote 3 effectively requires that all DERs are modeled, despite Footnote 7 allowing the procedure developed per R1 to define aggregation thresholds for DERs. Footnote 3 should instead read "For purposes of this item, aggregate Demand at each bus under item 1 is the Demand aggregated at the bus after removing any offsets due to DERs modeled at that bus according to the data requirements and reporting procedures developed by the PC and TPs per R1."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Please see the DT's clarifying updates made to footnote 3 of MOD-032-2. The intent of the DT was to tie connection between footnote 3 and footnote 7. In general, if there is a significant difference between gross load and net load, that is probably a good indication of where the DER aggregation threshold should be set. Nevertheless, the following could be added to FN3 if deemed necessary (and non-substantive by the DT: "Note that this may be impacted by an aggregation threshold for DER specified under footnote 7."	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

LG&E/KU does not support the revisions to MOD-032 due to the introduction of ambiguous compliance scenarios that are likely to arise from the revisions. The modifications to Requirement R1 Part 1.1 requiring the Transmission Planner (TP) to identify the entity responsible for providing data for all items in Attachment 1: (1) exceeded the scope of changes necessary to address FERC Order 901 directives, (2) removed certainty for functional entities regarding their obligations, and (3) failed to address FERC's explicit directive "to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System." In regard to point 3, it should be noted that the revised MOD-032 standard not only hands off the assignment of a responsible entity to TPs, it also fails to require that such entities be "registered entities."

The formerly described issues aside, the revisions to MOD-032 have the potential to put TPs in a spot where compliance with the standard is unclear. If a TP assigns an unregistered entity responsibility for providing DER data under Requirement R1 Part 1.1, and the unregistered entity fails to provide data (or estimated data), it is not clear who is in violation. The TP has correctly performed its job under Requirement R1 Part 1.1, but the unregistered entity is not subject to NERC standards The standard does not explicitly give the TP the right to provide its own estimate in these cases, nor does it say that the TP must assume the compliance burden on behalf of the unregistered entities. Ultimately, whether the TP supplements their own estimate or proceeds with no DER data, they venture into territory with unknown compliance repercussions.

Suggesting that TPs have other means to enforce compliance, such as stakeholder processes, is unsatisfactory. If this were always the case, compliance enforcement authorities would be redundant. LG&E/KU suggests that entities with sufficiently regulated processes that provide a reliable means of obtaining data from entities unregistered with NERC could be granted a regional variation of the standard. However, LG&E/KU maintains that the base NERC standard should be unambiguous on who provides data and that, in the case of DER connected to

unregistered entities, NERC must select a registered, functional entity to bear the compliance burden. LG&E/KU suggests striking modifications to Requirement R1 Part 1.1 and all associated changes.

As an alternative means of addressing the FERC Order 901 directives, LG&E/KU suggests either (1) that the Transmission Owner (TO) bear the responsibility for the data associated with unregistered IBRs and DERs connected to unregistered distribution providers, or (2) the that TO bear the responsibility for data associated with unregistered IBRs, and that the TP be responsible only for estimating the data associated with DERs connected to unregistered distribution providers (i.e., direct estimation rather than mandatory attempted data collection and subsequent estimation). For both options, registered Distribution Providers (DPs) should bear the responsibility for data associated with DERs connected to their systems. These options (1) do not make edits outside of the necessary scope to address FERC Order 901 directives, (2) preserve clarity of compliance obligations for functional entities, and (3) address FERC's explicit directive to determine the appropriate registered entity for providing data for DERs connected to unregistered distribution providers.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. In the hypothetical scenario provided, the TP should ensure that they identify a NERC-registered entity to provide data. The TP would not be "correctly performing" their job if assigning data obligations to unregistered entities that they have no assurance/expectation of getting data from. The Standard does not require the TP to assign data obligations to unregistered entities, but it allows such an exchange for cases where the TP has an opportunity to get better data from an unregistered entity. The DT views this as a more effective and efficient approach to meeting FERC 901 directives in various jurisdictions across the continent than having NERC dictate that TPs must only request/obtain certain data only from certain specific registered entities. Please also see the Technical Rationale for additional info on legacy language.

Isidoro Behar - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

As written, MOD-032-2, MOD-33, and MOD-026 reviews should be coordinated simultaneously to prevent potential conflicts and/or contradictory requirements. R2.1 should include a new measure that requires to provide evidence of estimation methods, assumptions, etc.,

for estimated data. As for the ERO Unacceptable Model List process, a decision-making window should be considered to not hamper case builds, and the process should coincide with interconnection case build cycles to streamline compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Each standard has a different process. This would depend upon each standard individually and does not make sense to be connected simultaneously. The team reviewed possible proposals for M2 and determined that the measure is accurate as drafted. It would be expected for an entity to provide evidence for the estimation piece following what the Requirement R2 Part language states. Regarding streamlining case builds, it may not be the same timeframe and changes to the Unacceptable Models List will be date stamped version as of beginning of case build would be considered. See the process outlined in the MOD-032 standard. Trying to align this would create complications to the process.	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	
SRP Supports the comments submitted by AEP related to the use of an unacceptable model in R2. The submission of an unapproved model should not be acceptable. The focus should be on unregistered IBRs as mentioned by other participants.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to AEP.	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

The proposed MOD-032-2 modifications contain inconsistencies to the term used throughout the standard (i.e.: "entity responsible". "functional entity", and "entity"). The only term defined is "functional entity" within Footnote 2. The inconsistency in language is confusing. The references need to be consistent throughout the document. The standard needs to clearly state who is responsible for the evidence required for Compliance. If a single designation is not possible, make clear that the PC and TP shall designated who is responsible in R1.1 and be consistent with the language throughout the Standard.

Requirement R2: Registered Tos and DP do not have the ability to provide or collect DER data from unregistered distribution providers. If this data is critical to the reliability of the BPS, then those unregistered distribution providers that have interconnecte4d DER that have a material impact on the BPS should be registered through NER registration criteria and added under 4.1 as a functional entity. We suggest the following language:

Distribution Providers (DPs) shall provide aggregate Distributed Energy Resource (DER) data for DERs that have been identified by the responsible PC and TP to have a material impact on the BPS. The DP shall estimate the modeling data and parameters and include an explanation of the limitations of the availability of data, and explanation of the limitations of the data provided, and the method used for estimation.

Requirement R3: There doesn't seem to be a mechanism that a PC or TP can use to compel the model provider to submit a model or data that is acceptable. There is a 90-day response period that could end as an end-less loop if the TP doesn't accept that the explanation where the technical basis doesn't respond to the technical concerns.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments.

As described in the Technical Rationale, "Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the "entity" to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement." In addition, the varying phrases should be read in context of how the standard is drafted. Functional entities are listed in the Applicability Section of the introduction in MOD-032-2.

There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data, but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1.

As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided

by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters." P. 106: "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation." It is expected that the PC/TP need to work with data providers. The proposed language is an improvement in that the previous language did not give the PC/TP any recourse if the responding entity responded but was not really responsive to the technical concern.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO supports the comments made by AEP.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to AEP.	
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	

The DT's Consideration of FERC Order 901 Directives said the following: " the DT did not know how to interpret **material affect** and therefore, left it up to the Planning Coordinator (PC) and each of its Transmission Planners (TP) to review, consider, and determine all unregistered IBR that would be materially impacted."

ACES asserts that the drafting team (DT) remains well within the scope of the directive in establishing a threshold to define "**material affect**" and suggests revising R2.1 as follows:

R2.1 – Each PC/TP shall, at their discretion, require R1 data from functional entities with 20 MVA or greater in total IBR-DER generation within their service territory.

R2.1.1 – For each functional entity with 20 MVA or greater in total IBR-DER generation within their service territory, the entity shall provide R1 data for individual IBR-DER units with a nameplate rating greater than or equal to 5 MVA.

Rationale for 20 MVA Threshold

Historical Precedent

- The 20 MVA threshold has historically served as a continent-wide bright-line criterion distinguishing facilities that materially affect Bulk Power System (BPS) reliability from those that do not.
- This threshold is further supported by its use in defining Category 2 GO/GOP IBRs.

Consistency Across Resource Types

- Fossil fuel generation units under 20 MVA are not required to provide this modeling data. Requiring non-BES IBR-DER data below this threshold would create an inconsistent and potentially inequitable standard.

Avoiding Regional Discrepancies

- Without a DT-defined threshold, PCs/TPs will inevitably apply varying criteria.

- Entities operating in multiple PC/TP areas could face inconsistent and burdensome reporting requirements.

Improved Data Quality and Model Accuracy

- Setting the threshold at 20 MVA total, with mandatory reporting for units ≥5 MVA, increases the likelihood of obtaining verifiable, high-quality data from functional entities.
- This approach reduces reliance on estimates for small units, resulting in more accurate models.
- Better models directly enhance BPS reliability.

ACES' member North Carolina's Electric Cooperatives shares the following in addition to the threshold advocated for by ACES: **"Without waiving any rights to assert jurisdiction overreach by NERC/FERC, and assuming for the sake of argument that authority exists: Each DP will coordinate with the RC/TP on projects < 5MVA as needed".**

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

As referenced in the Technical Rationale, NERC has published a study concluding that a 0 MW threshold is appropriate for data collection purposes. The DT concluded that even if a threshold was applied, data would still need to be collected to verify and ensure that a threshold was not being exceeded. Further, the DT determined that there is no strong technical justification for any particular universal DER threshold. If fact, any universal threshold would likely be inappropriate for many areas, so the DT created the flexibility for the PC/TP to make this determination for their local region. The proposed solution in the ACES comment does not address the potential aggregate impact of thousands of kW-scale DERs. The DT contends that the FERC concern is less about getting more detailed models for 5 MW (and larger) facilities (as most transmission planners are unlikely to utilize such detailed modeling for distribution-connected facilities) but being aware of and appropriately representing aggregations of smaller facilities at the T-D interface.

Material affect - see Consideration of FERC Directive. The DT stated: "Determination if an unregistered IBR or aggregate IBR-DER would “materially affect” the Bulk Power System, requires engineering judgment and is not something that would be appropriate to precisely specify in a reliability standard. Thus, Attachment 1 footnote 7 was added to explicitly allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas."	
George Goddard - DTE Energy - 5	
Answer	No
Document Name	
Comment	
I still struggle with R2 2.1: "If the responsible entity, as identified in Requirement R1 Part 1.1, is unable to gather unregistered Inverter-based Resource (IBR)1 data or aggregate Distributed Energy Resource (DER) data, the responsible entity shall estimate the modeling data and parameters and include an explanation of the limitations of 1 As used in this standard, the phrase “unregistered IBR” refers to a Bulk-Power System connected IBR that does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. MOD-032-21 — Data for Power System Modeling and Analysis Initial Draft of MOD-032-2 April 2025 Page 6 of 25 the availability of data, an explanation of the limitations of any data provided, and the method used for estimation. " This creates a burden to the DP and the data may not be accurate enough for study purposes. Documenting the limitations will not address the data inaccuracies. A possible recommendation is is to provide a mechanism for the unregistered DER”s to become registered and therefore subjected to the same compliance obligations as registered DER’s	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. A PC/TP could implement a more stringent requirement related to unacceptable models (e.g., not allowing them even with a rationale, or requiring the submission of a specific set of models) to align with a higher level modeling group such as the AMWG. Thus, it does not appear that MOD-032-2 would conflict with such a group, though the DT acknowledges that it would be beneficial for AMWG policies to align with the ERO document and MOD-032-2.	

If justification of an UM needing to be removed from the UML, can be provided through the process outlined in MOD-032.

If an unacceptable model is submitted without a technical rationale, it would be a compliance violation for the model submitter. Similar to any and every model that is submitted (even an "acceptable" model that is parameterized poorly and creates initialization or simulation issues), the TP and PC must make a determination of whether it can be used in a case-building process (with the acknowledgement that resolution of a model issue may not align with the deadline to finalize a base case). This may be completely separate from pursuing a technical concern under R3. MOD-032-2 does not specify any requirements for replacing or modifying unacceptable models, because that process is very dependent on the situation and requires engineering judgment (and finalizing a base case with the "unacceptable" model may end up being the best option).

Based on language from FERC Order 901, specific requirements for aggregate DER data are included in Attachment 1. However, other language from that order, which is incorporated in R2.1, recognized estimation may be necessary. This should be considered similarly to the understanding that load forecasts are not going to be 100% accurate, but provide valuable information nonetheless.

In addition, the DT answered this comment to the best of our ability. The comment received is confusing as it appears to be pointing to the first draft completed by the DT.

Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	No
Document Name	
Comment	

It does not appear that the language of the MOD-032 Supporting Document: Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) has considered the role of the Acceptable Models Working Group (AMWG) under Eastern Interconnection Reliability Assessment Group (ERAG) for building and maintaining the Eastern Interconnection models. But as part of the Standard, the Supporting Document likely supersedes the AMWG, and describes a more centralized process for the maintenance of the official Unacceptable Models List. It does not appear that the language provided by the SDT aligns with the charter of the AMWG, unless the AMWG fits into the general description of the "ERO Staff" under items 2 and 3.

It should be noted that the MOD-032 designee and associated industry groups comprised of Planning Coordinators may have a modeling group that reviews the technical rationale for using models on the ERO Unacceptable Models List (in R3). While outside of the Standard, this should provide consensus on the validity associated with any technical rationale provided by data submitters.

The present draft of MOD-032 does not include any requirement to modify or replace models that are submitted and are on the ERO Unacceptable Models List and do not have a valid technical rationale. This could be accomplished through the addition of a sub-requirement (R3.3).

To facilitate a timely model building process it may be beneficial to reduce the time that the functional entity has to respond to a technical concern from the PC/TP from 90 to 30 days (R3.2.).

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
A PC/TP could implement a more stringent requirement related to unacceptable models (e.g., not allowing them even with a rationale, or requiring the submission of a specific set of models) to align with a higher level modeling group such as the AMWG. Thus, it does not appear that MOD-032-2 would conflict with such a group, though the DT acknowledges that it would be beneficial for AMWG policies to align with the ERO document and MOD-032-2. If justification of an UM needing to be removed from the UML, can be provided through the process outlined in MOD-032.

If an unacceptable model is submitted without a technical rationale, it would be a compliance violation for the model submitter. Similar to any and every model that is submitted (even an “acceptable” model that is parameterized poorly and creates initialization or simulation issues), the TP and PC must make a determination of whether it can be used in a case-building process (with the acknowledgement that resolution of a model issue may not align with the deadline to finalize a base case). This may be completely separate from pursuing a technical concern under R3. MOD-032-2 does not specify any requirements for replacing or modifying unacceptable models, because that process is very dependent on the situation and requires engineering judgment (and finalizing a base case with the “unacceptable” model may end up being the best option).

In addition, the ERAG and MMWG is the MOD-032 designee per the process within the EASTERN INTERCONNECTION REGIONAL ENTITY AGREEMENT and is located on the MMWG website. See link to agreement language above. https://www.rfirst.org/wp-content/uploads/2023/10/EI-Regional-Entity-Agmt-Final-Signed.pdf An adjustment of the timeline in R3.2 of the currently approved MOD-032-1 was not in scope.

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

The MRO NSRF appreciates the SDT's consideration of comments in the previous ballot and the revisions to the standard made in response. However, the MRO NSRF still has the following concerns:

· The inconsistency of terms used throughout the standard (i.e.: "entity responsible ", "functional entity", "entity"). None of these terms are defined except "functional entity" in Footnote 2, and the inconsistency in language is confusing at best or even misleading, bringing ambiguity to a Reliability Standard. These references need to use a consistent term throughout the document. A Reliability Standard should clearly state who is responsible for the evidence required for Compliance. If a single designation is not possible, make it clear that the PC and TP shall designate who is responsible in R1.1 and be consistent with this language throughout the Standard.

· Requirement R2

While the MRO NSRF understands the need for improved modeling, Distribution Providers (DP) are the only entities who have information on DERs interconnected to their distribution systems. Registered entities (TO and DP) do not have the ability to provide or collect DER data from unregistered distribution providers. If this data is critical to the reliability of the BPS, then those unregistered distribution providers that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria and added under 4.1 as a Functional Entity. Moreover, DPs are to provide DER data that has a material impact on the BPS and subpart 2.1 should reflect this important consideration. To address our concerns, Distribution Providers (DPs) shall provide aggregate Distributed Energy Resource (DER) data for DERs that have been identified by the responsible PC and TP to have a material impact on the BPS. The DP shall estimate the modeling data and

parameters and include an explanation of the limitations of the availability of data, an explanation of the limitations of any data provided, and the method used for estimation.

· Requirement R3 Concerns

There doesn't seem to be any mechanism whereby a PC or TP can compel the model provider to submit a model or data that is acceptable. There is a 90-day response period that potentially become an end-less loop if the TP doesn't accept the explanation where the technical basis doesn't respond to the technical concerns.

· Section C: Compliance Concerns

Potential Noncompliance (PNC) Abeyance Period

This does not provide any sense of comfort to those entities that are providing estimates to the best of their knowledge that they will not be held in non-compliance by an auditor. This section needs further clarification and not be subject to any Auditor's interpretation. Use of ambiguous words such as "Good Faith" are not auditable and are very subjective and therefore inappropriate in a Reliability Standard. Additionally, there is no guarantee that the Abeyance Period is 1) long enough for NERC to create a new Registered entity (DP-DER) which was the original intent of the Abeyance, 2) will even be approved as it is still a "Potential".

· Section E: Associated Documents

"MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)"

As currently presented, this document is NOT part of the Reliability Standard and is NOT enforceable as such and should be maintained as a separate standalone document with the ERO Unacceptable Models List. To keep it at the end of the Standard gives the impression that it is enforceable and part of the standard. However, we believe that the Model Criteria should be included in the affected Reliability Standards and only changed when those Standards are modified and as such it should be an enforceable part of the standard and NOT an Associated Document as listed in Section E.

The MRO NSRF recommends removing the title from Section E as an Associated Document and making it part of MOD-032. Replace the title: MOD-032 Supporting Document with Attachment 2.

· Footnote concerns o Footnote 1: The MRO NSRF does not agree with Footnote 1. Data required should be specified within each sub-bullet of each column for both steady-state and dynamics. Failure to do this creates potential confusion. This situation is further amplified by the inclusion of new registered entities such as category 2 GOs. o Footnote 6: TO and DP have no ability to collect or provide aggregate data for DERs that are not connected to their system. If DER data is needed from unregistered DP to preserve the reliability of the BPS, then those entities should be registered.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. As described in the Technical Rationale, “Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the “entity” to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement.” In addition, the varying phrases should be read in context of how the standard is drafted. Functional entities are listed in the Applicability Section of the introduction in MOD-032-2.	

There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data, but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1.

As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."

P. 106: "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."

It is expected that the PC/TP need to work with data providers. The proposed language is an improvement in that the previous language did not give the PC/TP any recourse if the responding entity responded but was not really responsive to the technical concern.

At the outset, while any such abeyance period would need to be approved by the NERC Board of Trustees and the applicable governmental authorities, the phrase "potential noncompliance (PNC)" refers to a finding that an entity may have not complied with a Reliability Standard and not an abeyance period that NERC may or may not determine to pursue.

It is NERC's intent that the Potential Noncompliance Abeyance language would provide some assurance to entities that NERC would not pursue violations through the enforcement process provided that entities were taking steps to comply with the standard in "good faith". The phrase "good faith" is generally understood to require an "honest belief of purpose, faithful performance of duties, observance of dealing standards, or an absence of fraudulent intent." (Cornell Law School, Legal Information Institute). For example, an entity provided its estimates and supporting explanations in a timely manner and consistent with TP/PC data specification and reporting instructions, but there was some dispute about the quality of the estimate provided or the effort taken to collect data from the owner. While such compliance language is not subject to industry ballot, NERC appreciates the feedback and has revised the section to provide more clarity consistent with the comment.

Entities are correct in that they are not subject to compliance with the Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) located at the end of MOD-032-2 Standard. The Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) actual document will be maintained outside standards due to the possibility that other standards may choose to reference this particular document. The process located in MOD-032 holds the ERO accountable by having to follow the process when adding or removing an unacceptable model to or from the list itself. At this time, the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) can be located on the 2022-02 project page of the NERC website. Following the October 2025 launch of the new NERC website, entities will be able to locate the Unacceptable Models List on the MOD-032-2 Standards page. While the MOD-032 page has not been developed yet, here is the link to access what the MOD-032-1 page looks like. Each standard will have its own standards page to access the standard, implementation plan, and other important documents associated with that specific standard.

In addition, to prevent confusion, the 4th bullet under Section E has been removed and additional language has been added to the MOD-032 Supporting Document page. To be clear, NERC must follow the process specified at the end of MOD-032, and if any changes to the process need to be made, a standards development project must be created to modify the process itself. This approach ensures consistency in the process of maintaining the ERO Unacceptable Models List.

Footnote 1:
No changes to Footnote 1. GO would be included upon the enforcement date. Jordan to look up date. See response in first comment to ATC. This footnote focuses on PC/TP and not the GO.

Footnote 6: As mentioned above, under the proposed definition of Generator Owner adopted by the NERC Board in August 2025 and pending FERC approval, the term "Generator Owner" as used in MOD-032-2 would include owners of both Category 1 and Category 2 assets. In MOD-032-2 case, it refers to both and no changes need to be made. When a DP is unregistered, the TP/PC will identify the appropriate entity. The TO tends to be the best back up, but based on comments received over the drafts, this flexibility is needed for some entities who would lean on other entities to gather the data needed.	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

While we support the efforts of the drafting team for Draft 2 of MOD-032, there are concerns.

{C}· Use of varying phrases of "entity responsible "or "functional entity", or "entity". None of these terms are defined except "functional entity" in Footnote 2 and are confusing at best or misleading, bringing ambiguity to a Reliability Standard. This needs to be consistent throughout the document whichever term is used. A Reliability Standard should know who is responsible for what is required for Compliance. If not, make it clear that the PC and TP shall designate who is responsible in R1.1 and be consistent with this language throughout the Standard.

R1.1 The data listed in Attachment 1, including the entity responsible for each required item **as determined by the PC and TP.**

{C}· Alignment with Project 2024-01

ATC does not agree that MOD-032-2 has been sufficiently aligned with the Project 2024-01 Implementation Plan. As stated in the Project 2024-01 Implementation Plan that Category 2 GOs will be held responsible for GO requirements contained in MOD-032, yet the currently proposed MOD-032-2 Reliability Standard Applicability Section does not clearly identify those entities. While we recognize the proposed definition of GO includes both Category 1 & 2, ATC submits that that the following clarifying addition be added to 4.1.3 of the Applicability Section of MOD-032-2 (shown in **boldface**):

4.1.3 Generator Owner **- Category 1 and 2**

{C}· Requirement R2 Concerns

While it is understood that there is a need for improved modeling, Distribution Providers (DP) are the only entities who have information on DERs interconnected to their distribution systems. Registered entities (TO and DP) do not have the ability to provide or collect DER data from unregistered DP. If this data is critical to the reliability of the BPS, then unregistered DPs that have interconnected DERs that have a material impact on the BPS should be registered through NERC registration criteria and added as under 4.1 as a Functional Entity. Moreover, DPs are to provide DER data that has a material impact on the BPS and subpart 2.1 should reflect this important consideration. To address our concerns, **Distribution Providers (DPs) shall provide** aggregate Distributed Energy Resource (DER) data **for DERs that have been identified by the responsible PC and TP that have a material impact on the BPS**. **T**he **DP** shall estimate the modeling data and parameters and include an explanation of the limitations of the availability of data, an explanation of the limitations of any data provided, and the method used for estimation.

{C}· Requirement R3 Concerns

There doesn't seem to be any mechanism whereby a PC or TP can compel the model provider to submit a model or data that is acceptable. There is a 90-day response period that potentially could end as an end-less loop if the TP doesn't accept that the explanation where the technical basis doesn't respond to the technical concerns.

{C}· Attachment 1 Concerns

Steady State Concerns

Item 9 **–** TOs are entirely dependent on DPs and should therefore be removed from have direct responsibility for Aggregate DER data.

Dynamics Concerns

Item 10 – Consistent with previous comments, TOs should be removed from Item 10. They have no ability to provide aggregate DER data on any distribution system (registered or unregistered) because they do not own or interconnect those resources directly.

For DERs that are connected to UFLS Only DPs distribution providers, aggregated DER data connected to their distribution systems and information detailing DERs connected to UFLS schemes should be obtained from those registered entities. Additionally, UFLS and UVLS tripping capacity of DERs should be provided

The term “aggregate” should also be clarified for Item 10.

To address our concerns, we offer the following edits (in **boldface** and strikethrough):

10. Aggregate Distributed Energy Resource (DER) data [DP, TOs **UFLS DPs**]

b. Indication whether DERs is subject to tripping in conjunction with are part of any UFLS or UVLS schemes **and provide estimates of the affected aggregated tripping capacity on those schemes.**

{C}· Section C: Compliance Concerns

Potential Noncompliance (PNC) Abeyance Period

This does not provide any sense of comfort to those entities that are providing estimates to the best of their knowledge that they will not be held in non-compliance by an auditor. This section needs further clarification and not subject to any Auditor’s interpretation. Use of ambiguous words such as Good Faith are not auditable and very subjective and inappropriate in a Reliability Standard. And there is no guarantee that the Abeyance Period is 1) long enough for NERC to create a new Registered entity (DP-DER) which was the original intent of the Abeyance, 2) will even be approved as it is still a “Potential”.

{C}· Section E: Associated Documents

MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) in the standard. It is NOT part of the Reliability Standard and is NOT enforceable as such and should be maintained as a separate standalone document with the ERO Unacceptable Models List.

To keep it at the end of the Standard gives the impression that it is enforceable and part of the standard.

However, we believe that the Model Criteria should be included in the affected Reliability Standards and only changed when those Standards are modified and as such it should be an enforceable part of the standard and NOT an Associated Document as listed in Section E.

Recommendation is to remove the title from Section E as an Associated Document and make it part of MOD-032. Replace the title: *MOD-032 Supporting Document* with *Attachment 2*.

{C}· Footnote concerns

Footnote 1**:**

ATC does not agree with Footnote 1. Data required should be specified within each sub-bullet of each column for both steady-state and dynamics. Failure to do this creates potential confusion. This situation is further amplified by the inclusion of new registered entities such as category 2 GOs.

Footnote 6**:**

TO and DP have no ability to collect or provide aggregate data for DERs that are not connected to their system. If DER data is needed from unregistered DP to preserve the reliability of the BPS, then those entities should be registered.

Likes 0	
Dislikes 0	

Response

Thank you for your comments.
As described in the Technical Rationale, “Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the “entity” to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an

administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement." In addition, the varying phrases should be read in context of how the standard is drafted. Functional entities are listed in the Applicability Section of the introduction in MOD-032-2.

There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data, but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1.

As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."

P. 106: "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their

areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."

It is expected that the PC/TP need to work with data providers. The proposed language is an improvement in that the previous language did not give the PC/TP any recourse if the responding entity responded but was not really responsive to the technical concern.

At the outset, while any such abeyance period would need to be approved by the NERC Board of Trustees and the applicable governmental authorities, the phrase "potential noncompliance (PNC)" refers to a finding that an entity may have not complied with a Reliability Standard and not an abeyance period that NERC may or may not determine to pursue.

It is NERC's intent that the Potential Noncompliance Abeyance language would provide some assurance to entities that NERC would not pursue violations through the enforcement process provided that entities were taking steps to comply with the standard in "good faith". The phrase "good faith" is generally understood to require an "honest belief of purpose, faithful performance of duties, observance of dealing standards, or an absence of fraudulent intent." (Cornell Law School, Legal Information Institute). For example, an entity provided its estimates and supporting explanations in a timely manner and consistent with TP/PC data specification and reporting instructions, but there was some dispute about the quality of the estimate provided or the effort taken to collect data from the owner. While such compliance language is not subject to industry ballot, NERC appreciates the feedback and has revised the section to provide more clarity consistent with the comment.

Entities are correct in that they are not subject to compliance with the Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) located at the end of MOD-032-2 Standard. The Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) actual document will be maintained outside standards due to the possibility that other standards may choose to reference this particular document. The process located in MOD-032 holds the ERO accountable by having to follow the process when adding or removing an unacceptable model to or from the list itself. At this time, the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) can be located on the 2022-02 project page of the NERC website. Following the October 2025 launch of the new NERC website, entities will be able to locate the Unacceptable Models List on the MOD-032-2 Standards page. While the MOD-032 page has not been developed yet, here is the link to access what the MOD-032-1 page looks like. Each standard will have its own standards page to access the standard, implementation plan, and other important documents associated with that specific standard.

In addition, to prevent confusion, the 4th bullet under Section E has been removed and additional language has been added to the MOD-032 Supporting Document page. To be clear, NERC must follow the process specified at the end of MOD-032 and if any changes to the process

need to be made, a standards development project must be created to modify the process itself. This approach ensures consistency in the process of maintaining the ERO Unacceptable Models List.

Footnote 1:
No changes to Footnote 1. GO would be included upon the enforcement date. Jordan to look up date. See response in first comment to ATC. This footnote focuses on PC/TP and not the GO.

Footnote 6:
As mentioned above, under the proposed definition of Generator Owner adopted by the NERC Board in August 2025 and pending FERC approval, the term "Generator Owner" as used in MOD-032-2 would include owners of both Category 1 and Category 2 assets. In MOD-032-2 case, it refers to both and no changes need to be made. When a DP is unregistered, the TP/PC will identify the appropriate entity. The TO tends to be the best back up, but based on comments received over the drafts, this flexibility is needed for some entities who would lean on other entities to gather the data needed.

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	

While the drafting team has attempted to acknowledge the need for an aggregation threshold for DER that materially affects the reliability of the Bulk Power system and has added footnote 7 to attachment 1, footnote 3 contradicts this consideration by omitting a minimum threshold for which gross demand and DER aggregation would not need to be segregated, therefore inadvertently requiring a DP to have all information necessary to account for the DER and rendering provisions under requirement R2.1. useless. R2.1 focuses on aggregate DER data and not gross demand data which is impacted by DER data. DP's may have specific RERRA-jurisdictional regulatory limitations that prevent a DP's ability to parse gross demand from net demand due to BTMG. This is potentially avoided by setting an adequate minimum threshold for DER sizing determined to materially affect the reliability of the bulk power system, filtering out the smaller DER installations where separate metering is unavailable. We recommend the drafting team should expand the intent of footnote 7 to apply to gross vs net demand aggregations in footnote 3 or expand provisions in R2.1 to acknowledge aggregations of gross demand and DER resources, allowing for explanation of limitations in supporting data reporting for aggregate demand as currently defined in attachment 1.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Please see the DT's clarifying updates made to footnote 3 of MOD-032-2. The intent of the DT was to tie connection between footnote 3 and footnote 7.

In general, if there is a significant difference between gross load and net load, that is probably a good indication of where the DER aggregation threshold should be set. Nevertheless, the following could be added to FN3 if deemed necessary (and non-substantive by the DT: "Note that this may be impacted by an aggregation threshold for DER specified under footnote 7."

Based on language from FERC Order 901, specific requirements for aggregate DER data are included in Attachment 1. However, other language from that order which is incorporated in R2.1 recognized estimation may be necessary. This should be considered similarly to the understanding that load forecasts are not going to be 100% accurate but provide valuable information nonetheless.

Wesley Yeomans - New York State Reliability Council - 10

Answer	No
Document Name	

Comment

We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Estimation is only allowed in areas where unregistered DER data cannot be collected. This is for the typical entity, which would be the Distribution Provider and Transmission Owner. Requirement R2 Part 2.1 is an "if" statement. If you already have the data, then you would not need to complete 2.1. See FERC Order No. 901 P 104.

Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	

NextEra agrees with the modifications to MOD-032, however supports EEI's request to modify the Abeyance language of Section C, as provided below:

For a period of two years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C **of** the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data **for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided.** Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

BPA reiterates its previous comment regarding the TO not being the "appropriate registered entity to be responsible for providing estimations of unregistered load". BPA asserts 'actual' data is the foundation for modeling of the bulk-power system. Without this crucial information,

BPA believes estimating small/discrete unregistered IBRs is vague and doesn't lend itself to creating models aligned with industry 'best practice' standards. BPA continues to recommend estimated base information come from the Regional Entity or require the submission of valid data from registered DER and IBR generators.

Additionally, as the DT mentioned in its response to industry comments "modifying NERC registration criteria is not a feasible option for addressing FERC 901 directives within the required timelines", BPA believes a better, more 'actual' data driven alternative for future consideration, is requiring unregistered entities register under a new compliance registry type, such as "DP-DER".

As this is a new area of focus, opportunity to learn, and refine, BPA agrees with the DT's Technical Rationale that this standard is a great candidate for an abeyance period. BPA appreciates the inclusion of Section C, bullet 2, CMEP, Potential Noncompliance (PNC) Abeyance Period. This will allow industry to adapt, gain a better understanding, and make the necessary improvements.

In conclusion, BPA appreciates the urgency that NERC is responding to FERC directives but asserts NERC reliability standards should drive reliability. BPA believes grid modeling from 'actual' data leads to reliable outcomes.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. FERC Order 901 directed estimation. As described in the Technical Rationale, "Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the "entity" to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement." In addition, the varying phrases

should be read in context of how the standard is drafted. Functional entities are listed in the Applicability Section of the introduction in MOD-032-2.

There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1.

As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."

P. 106: "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."

It is expected that the PC/TP need to work with data providers. The proposed language is an improvement in that the previous language did not give the PC/TP any recourse if the responding entity responded, but was not really responsive to the technical concern.

This is an option for entities who are unable to gather the data. In addition, NERC staff is looking into future registration, but making that happen did not fit within the timeline of this project.

Thank you for your support on other parts. Abeyance period.

Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
We do not agree with R2.1; estimating parameters is not appropriate. If additional data is needed, then it should be required for those GO/GOP entities to submit it to the applicable authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Estimation is only allowed in areas where unregistered DER data cannot be collected. This is for the typical entity, which would be the Distribution Provider and Transmission Owner. Requirement R2 Part 2.1 is an "if" statement. If you already have the data, then you would not need to complete 2.1. See FERC Order No. 901 P 104.	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation does not object to the proposed changes made to MOD-032-2, however we do agree with EEI's suggested non-substantive changes for the drafting team to consider.	

We agree with the concerns shared by EEI members that the lack of specificity regarding the delegation to the PC & TP to determine which entities are responsible for the data requirements in Attachment 1 could lead to some unforeseen difficulties in requesting the data, especially when non-registered entities are involved. The Abeyance Language helps for the short term but may not be the best long-term solution. Black Hills Corporation agrees with EEI on removing bullet 4 from Section E "Process for Updating the Unacceptable Models List Maintained by the ERO" since this is already an attachment to MOD-032-2. This process document should be marked as Attachment 2 to clearly show separation between it and Attachment 1. Black Hills Corporation also agrees with the changes to the Abeyance Language suggested by EEI to make it more clear. The suggested changes from EEI are in bold below: For a period of two years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C **of** the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data **for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided.** Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

CEHE supports EEI comments as proposed.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
USV understands the FERC Order 901 directives and the need to approve the MOD-032 modifications as proposed. However, there are still concerns with the resources required for entities to fulfill the obligations, this is particularly important for smaller entities with limited	

budgets and time. USV believes that once the standard is implemented, the industry can gain a better understanding of how to achieve the same reliability gain without any additional burdens on entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon supports the enhancements suggested in the comments submitted by the EEI.	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

AZPS supports the following comments submitted by EEI on behalf of its members.

EEI members continue to have concerns related to the decision to delegate to the PC and TP, in Requirement 1, the determination of which entities are responsible for the data requirements contained in Attachment 1. To clarify their concerns, this lack of specificity has the potential of creating unforeseen difficulties for both the PCs and TPs requesting the data and those entities identified as being responsible for supplying this data, particularly where non-registered entities are involved. And while the Abeyance language will likely be helpful at alleviating these problems in the short term, it is unclear whether this temporary solution will remedy this issue over the long term.

EEI suggests deleting from Section E (Associated Documents) bullet 4, "Process for Updating the Unacceptable Models List Maintained by the ERO" since this document is an attachment to MOD-032-2. Additionally, this process document should be marked and identified as Attachment 2, because as currently contained within MOD-032-2 there is no separation between Attachment 1 and this process document.

Finally, EEI appreciates the inclusion of the Abeyance Language, however, the language could be clearer and less repetitive. The subjectivity of the language (e.g., sincere intent) should be removed because it places unnecessary compliance risk on the functional entities responsible. To resolve our concerns, we offer the following suggested language for NERC consideration.

For a period of two years following the enforcement date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C of the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or

estimated data for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Regarding R1.4.2 - It is unclear whether this should be applied retroactively to the existing user written models. Its better that this be explicitly clarified within the standard itself .	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT understands that your question is whether this new provision in MOD-032 would retroactively be applied. Standards are not retroactively applied. Entities are to comply with the MOD-032 specification that is then in effect.	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF	
Answer	Yes

Document Name	
Comment	
Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee	
Answer	Yes
Document Name	2022-02_Unofficial_Comment_Form SRC.docx
Comment	
In Attachment 1, page 15, the ISO/RTO Council (IRC) Standards Review Committee (SRC) requests additional clarity regarding the following statement: *"The joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify each entity's responsibility and data flow processes."* In the Consideration of Comments, could the drafting team please clarify how detailed the expectations are with respect to the data flow? Specifically, to what level of granularity should entities describe responsibilities and data exchanges within these processes?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The DT recognizes that PC/TP data collection practices vary across the continent, and it would not be appropriate for NERC to mandate a particular process for collecting data. There is no "granularity" expectation, but entities within the process should understand their roles. For example, a DP may be required to provide DER data, but the process may require that data to be provided through a TP or TO rather than requiring data to be provided directly from the DP to the PC.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC does not object to the proposed changes made to MOD-032-2 and appreciates the improvements made since Draft 1. However, we offer some input and non-substantive changes for DT consideration. ITC continues to have concerns related to the decision to delegate to the PC and TP, in Requirement 1, the determination of which entities are responsible for the data requirements contained in Attachment 1. To clarify our concern, this lack of specificity has the potential of creating unforeseen difficulties for both the PCs and TPs requesting the data and those entities identified as being responsible for supplying this data, particularly where non-registered entities are involved. And while the Abeyance language will likely be helpful at alleviating these problems in the short term, it is unclear how this will affect compliance on this issue over the long term.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The PC/TP should be able to develop data procedures that allow the data to be obtained from the best and most reliable sources available. The DT believes that this is best determined at the PC/TP level rather than dictated by NERC in MOD-032. The DT does not anticipate PCs and TPs requiring data from unregistered entities without some level of assurance (local authority, etc.) that those entities are the best and most reliable sources of information. The fact is that industry largely depends on data from entities that are not registered under NERC (OEMs, vendors, consultants, etc.) and it could be detrimental to reliability and model fidelity to obligate the MOD-032 PC/TP data procedures to only point to NERC-registered entities for data collection.	
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 EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) aligns with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI does not object to the proposed changes made to MOD-032-2 and appreciates the improvements made since Draft 1. However, we offer some non-substantive changes for DT consideration.

Some EEI members continue to have concerns related to the decision to delegate to the PC and TP, in Requirement 1, the determination of which entities are responsible for the data requirements contained in Attachment 1. This lack of specificity has the potential of creating unforeseen difficulties for both the PCs and TPs requesting the data and those entities identified as being responsible for supplying this data, particularly where non-registered entities are involved. And while the Abeyance language will likely be helpful at alleviating these problems in the short term, it is unclear whether this temporary solution will remedy this issue over the long term. Nevertheless, we look forward to working with NERC to resolve any issues that might arise surrounding this concern, should this issue manifest itself into legitimate problems.

EEI suggests deleting from Section E (Associated Documents) bullet 4, "Process for Updating the Unacceptable Models List Maintained by the ERO" since this document is an attachment to MOD-032-2. Additionally, this process document should be marked and identified as Attachment 2, because as currently contained within MOD-032-2 there is no separation between Attachment 1 and this process document.

Finally, EEI appreciates the inclusion of the Abeyance Language, however, the language could be clearer**.** The subjectivity of the language (e.g., sincere intent) should be removed because it places unnecessary compliance risk the functional entities responsible. To resolve our concerns, we offer the following edits in boldface for NERC consideration. (*STRIKETHROUGHS REMOVED*)

For a period of two years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C **of** the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data **for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop estimates for aggregate DER data and unregistered IBR data that include the supporting data explanation and methods used as detailed in Requirement R2 subpart 2.1, they will pursue actions against entities who do not supply the required estimates, or the explanation of the limits or their methods used to create the estimates provided.** Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The PC/TP should be able to develop data procedures that allow the data to be obtained from the best and most reliable sources available. The DT believes that this is best determined at the PC/TP level rather than dictated by NERC in MOD-032. The DT does not anticipate PCs and TPs requiring data from unregistered entities without some level of assurance (local authority, etc.) that those entities are the best and most reliable sources of information. The fact is that industry largely depends on data from entities that are not registered under NERC (OEMs, vendors, consultants, etc.) and it could be detrimental to reliability and model fidelity to obligate the MOD-032 PC/TP data procedures to only point to NERC-registered entities for data collection. • Please see the updated abeyance language. • Bullet 4 from section E has been removed. • Please see updated language added to the MOD-032-2 supporting document section of the standard.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	Yes
Document Name	
Comment	
SPP supports the comments provided by the IRC Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to IRC SRC.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

EEI does not object to the proposed changes made to MOD-032-2 and appreciates the improvements made since Draft 1. However, we offer some non-substantive changes for DT consideration.

Some EEI members continue to have concerns related to the decision to delegate to the PC and TP, in Requirement 1, the determination of which entities are responsible for the data requirements contained in Attachment 1. This lack of specificity has the potential of creating unforeseen difficulties for both the PCs and TPs requesting the data and those entities identified as being responsible for supplying this data, particularly where non-registered entities are involved. And while the Abeyance language will likely be helpful at alleviating these problems in the short term, it is unclear whether this temporary solution will remedy this issue over the long term. Nevertheless, we look forward to working with NERC to resolve any issues that might arise surrounding this concern, should this issue manifest itself into legitimate problems.

EEI suggests deleting from Section E (Associated Documents) bullet 4, "Process for Updating the Unacceptable Models List Maintained by the ERO" since this document is an attachment to MOD-032-2. Additionally, this process document should be marked and identified as Attachment 2, because as currently contained within MOD-032-2 there is no separation between Attachment 1 and this process document.

Finally, EEI appreciates the inclusion of the Abeyance Language, however, the language could be clearer**.** The subjectivity of the language (e.g., sincere intent) should be removed because it places unnecessary compliance risk the functional entities responsible. To resolve our concerns, we offer the following edits in boldface for NERC consideration. (*STRIKETHROUGHS REMOVED*)

For a period of two years following the **enforcement** date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C **of** the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data **for unregistered IBRs. While the CEA will not pursue compliance actions during this period for entities who develop**

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Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathon Flores - Los Angeles Department of Water and Power - 1,3,5,6	

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 Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
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	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
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	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - TXNM Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 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	

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; John Nierenberg, 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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
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	
Document Name	

Comment
Southern Company does not object to the proposed changes made to MOD-032-2 and appreciates the drafting team's efforts in addressing concerns from Draft 1 of MOD-032-2. However, we offer some input and non-substantive changes for the DT consideration. Requirement R1 Part 1.1 and Attachment 1 - While Southern Company appreciates the clarification provided in the technical rationale, Southern Company is concerned that not requiring the PC/TP to designate NERC registered functional entities in Requirement R1 could lead to a gap in enforceability. Southern Company recommends adding the word 'Functional' in front of entities to make it clear that the standard requires the PC/TP to designate registered functional entities. While Southern Company agrees that data can be sourced from both registered and unregistered entities, a registered entity must be specified as responsible in Requirement R1 for Requirement R2 to be fully enforceable. Requirement R2 Part 2.2 – Southern Company appreciates the alignment of proposed standards MOD-032-2 and MOD-026-2. While the intent is clear in the technical rationale, Southern Company proposes the language below to better align with MOD-026-2. "…, the functional entity shall provide the models **that its Transmission Planner received and provided a written notification that the model(s) and accompanying documentation are acceptable in accordance with** MOD-026, where such models are available." Additionally, Southern Company supports EEI Comments.
Likes 0
Dislikes 0
Response
Thank you for your comments. The PC/TP should be able to develop data procedures that allow the data to be obtained from the best and most reliable sources available. The DT believes that this is best determined at the PC/TP level rather than dictated by NERC in MOD-032. The DT does not anticipate PCs and TPs requiring data from unregistered entities without some level of assurance (local authority, etc.) that those entities are the best and most reliable sources of information. The fact is that industry largely depends on data from entities that are not registered under NERC (OEMs, vendors, consultants, etc.) and it could be detrimental to reliability and model fidelity to obligate the MOD-032 PC/TP data procedures to only point to NERC-registered entities for data collection. • Please see the updated abeyance language.

- Bullet 4 from section E has been removed.
- Please see updated language added to the MOD-032-2 supporting document section of the standard.

2. Do you agree with the proposed IRO-010-6 and TOP-003-8 modifications? If you do not support the modifications made, please provide rationale and proposed language on how you would address the FERC Order 901 directives.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
As IRO-010-6, Requirement R1, Part 1.1 is currently drafted, it is unclear if the phrase "as deemed necessary by the Reliability Coordinator" at the end of Part 1.1 applies only to "identification of the entities responsible for responding to the specification" or if it applies to every category of data and information listed in Part 1.1. To address this ambiguity, ERCOT recommends that the phrase "as deemed necessary by the Reliability Coordinator" be moved from the end of Part 1.1 to the beginning of the list of data and information in Part 1.1, as follows: A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments**, *as deemed necessary by the Reliability Coordinator*,** including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification. A similar ambiguity exists in the current draft of TOP-003-8. Consequently, ERCOT recommends that corresponding modifications be made to Requirement R1, Part 1.1 and Requirement R2, Part 2.1 in TOP-003-8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the updated language in the IRO-010 and TOP-003 standards.	
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; John Nierenberg, 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 does not support TOP-003 R1.5.3 because there is a lack of clarity and ambiguity in the Requirement language, as noted by other entities' comments (specifically, BPA).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to other entity's comments. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The MRO NSRF would appreciate more clarity on “as applicable” as it is used in multiple sub-requirements throughout these two standards. Additionally, the MRO NSRF requests the changes to TOP and IRO be based upon requirements for using the data, potentially as envisioned in Milestone 4. As written, the use of planning models in the real-time operations, “as applicable”, seems to create a requirement the RC or BA gather data that may be of no value to these entities. Under the current standards, the information needed may be gathered by those entities if it is needed for reliability. If this change stands, it may require the RC and BA gather data for compliance purposes only and provide no real time value.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The inclusion of “as applicable” allows for variation as necessary for application in the operations horizon. For example, consistent models would not be appropriate if an update was made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
SPP supports the comments provided by the IRC Standards Review Committee	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to IRC SRC.	
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 the opinion of ACES that NERC registered entities should not be subjected to potential violations of multiple NERC Reliability Standards Requirements for a single action. In other words, we contend that by including requirements for model submissions in both MOD-032-2 and in a documented data specification(s), responsible entities will now be subject to a form of double jeopardy (i.e., claim preclusion). ACES recommends only requiring model submissions under MOD-032-2 and subsequently striking the following newly proposed requirement parts: IRO-010-6 Requirement R1 Part 1.5.3, TOP-003-8 Requirement R1 Part 1.5.3, and TOP-003-8 Requirement R2 Part 2.5.3.	
Likes 0	
Dislikes 0	
Response	
Thank You for your comments. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. TOP and IRO allow the RC, TOP, and BA to determine what is necessary to provide. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	

Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form SRC.docx
Comment	
The RC and BA are able to obtain the necessary model information to support real time assessments, real-time monitoring, and analysis within the current standards. Accordingly, we believe the proposed modification is unnecessary. Until such time as there is an obligation on the RC or BA to use the data in real time, then these changes are premature or unwarranted SRC is concerned about the phrasing with "as applicable" and the requirements to use planning models. This phrase is unclear for how it may be applied during an audit. Additional clarity could be added by clarifying at the discretion of the RC, these models may be used. If there are criteria envisioned it would be more appropriate to document those in the standard itself rather than leverage the planning models in the operational requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Models used in operations should be consistent with those used in planning as applicable. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. One example where consistent models would not be	

appropriate is an update made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	
The focus should be on using data for real-time operations that do not gather data as mentioned by other participants. These standards (IRO-010/TOP-003) were created to have needed data that have been produced by other standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. TOP and IRO allow the RC, TOP, and BA to determine what is necessary to provide. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
Answer	No
Document Name	
Comment	
TAL believes the intent of 2.5.3 is well intended, but that this standard does not belong in TOP-003-8, R2. R2 is a BA standard. R2.5.3 seems to be a modeling standard. R2.5.3 seems redundant with respect to other modeling and commissioning standards being developed. TAL believes that in all practical sense, this must be accomplished in planning standards, which come into play during interconnection studies, model verification and validation processes and commissioning.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. TOP and IRO allow the RC, TOP, and BA to determine what is necessary to provide. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro appreciates the drafting team responsiveness to our comments and the subsequent revisions to Requirements R1 Part 1.5.3 in IRO-010-6 and TOP-003-8 and Requirement R2 Part 2.5.3 in TOP-003-8, which now require the RC, BA and TOP functions to maintain in their data	

specs methods for entities to provide data and information, including “Requirements for model submissions to be consistent with the model submitted for planning purposes”. We noted in the Technical Rationale the stated objective of aligning the planning and operations models with reference to MOD-032-2, applicable on the Long-term Planning Time Horizon, as the typical driver for planning models submission. However, BC Hydro suggests that additional clarity in the context of the IRO-010 and TOP-003 standards, which are applicable in the Operations Planning Time Horizon, on modeling requirements possibly not in scope of the RC/BA/TOP. If the intent is to mandate that entities identified in R1 Part 1.1 to submit system models consistent with those generated per MOD-032-3 (where possible as discussed in the Technical Rationale), BC Hydro suggests that the wording be revised to better reflect this. As drafted, it is not immediately clear which requirements the data spec documentation must include, and whether these requirements pertain to the models, models submission, or both. Proposed wording for 1.5.3: Provisions for any model required for submission under the R1 data specification be consistent with the models created in accordance with MOD-032-2.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thanks for your comments. Models used in operations should be consistent with those used in planning as applicable. The inclusion of “as applicable” allows for variation as necessary for application in the operations horizon. One example where consistent models would not be appropriate is an update made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	
Modeling data requirements should not be part of real-time data and information specification documents. Modeling data should remain in MOD standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. TOP and IRO allow the RC, TOP, and BA to determine what is necessary to provide. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	
Kelly Heims - Central Iowa Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Central Iowa Power Cooperative supports the comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to ACES.	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed modification contained in both IRO-010-6 and TOP-003-8.	
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 EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the proposed IRO-010-6 and TOP-003-8 modifications.	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed modification contained in both IRO-010-6 and TOP-003-8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Portland General Electric (PGE) aligns with EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI.	
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 EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes

Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CEHE has no further comment.	
Likes 0	
Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
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 found no issues with updates to IRO-010-6 and TOP-003-8.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Per the NERC ROP, Section 300, reliability standards should use 'clear language': "Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance". With that, BPA has concerns as to how the proposed TOP-003 R1.5.3 language "consistent with the model submitted for planning purposes, as applicable" will be	

interpreted by an auditor. BPA believes the current state estimation model and planning models differ in many cases. Where there are differences, those differences are usually driven by the unavailability of real time data for that model or the need to simplify it to obtain consistent solutions. In the technical rationale document, the drafting team claims the "as applicable" addresses that. Based on the seemingly open nature of R1.5.3, BPA has uncertainty that industry's interpretation of "as applicable" will be the same as that of an auditor. BPA seeks clarity from the drafting team.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Thank you for your comments. Models used in operations should be consistent with those used in planning as applicable. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. One example where consistent models would not be appropriate is an update made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	

Dislikes 0	
Response	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 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	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 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	

Scott Thompson - TXNM Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
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	

Isidoro Behar - Long Island Power Authority - 1	
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; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
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	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
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	

Joshua London - Eversource Energy - 1,3, Group Name Eversource	
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	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

3. Do you agree that the modifications for the proposed reliability standards (MOD-032-2, IRO-010-6, and TOP-003-8) address the scope of the standard authorization request (SAR) in a cost-effective manner? If you do not agree, please provide alternatives that would address the SAR scope in a more cost-effective manner.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Regarding FirstEnergy's response to Q1 and Q2, FirstEnergy cannot determine the cost-effectiveness of achieving compliance toward this modification of MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to Q1 and Q2.	
Kelly Heims - Central Iowa Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Central Iowa Power Cooperative supports the comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to ACES.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE does not have comments.	
Likes 0	
Dislikes 0	
Response	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	
Obtaining data from unregistered entities is not cost efficient. Having redundant tasks in multiple standards does not add to cost savings as mentioned by other participants.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Per FERC Order 901 P 103: “We recognize that there may be limitations on the ability of certain transmission owners to provide all data about unregistered IBRs that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System. Likewise, there may be limitations on the ability of certain distribution providers to provide all data about IBR-DERs in the aggregate that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System.” Based on this information, it was determined that an estimation is better than nothing, and this is only needed if the functional entity is unable to gather data needed from the respective entity. When new requirements are created, there is going to come change in work. The DT did the best it could to ensure administrative burdens on entities outside of what is required from the FERC Order. In addition, it may not end up being the TOs responsibility based on the outcome of Requirement R1. See TR. There is DER in certain markets that provides other data, etc.
Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee

Answer	No
Document Name	2022-02_Unofficial_Comment_Form SRC.docx
Comment	
TOP-003 and IRO-010 Requirements to gather data that is not needed or utilized by the RC or BA become an administrative burden to track and assess. Other expenses to store the unnecessary data highlight the ineffectiveness of costs.	
Likes 0	

Dislikes 0	

Response
Thank you for your comment. The DT reviewed existing IRO-010 and TOP-003 versions and found that both standards had broad requirements language that encompassed generation and storage resources, including IBR. Nevertheless, to ensure no ambiguity that FERC Order 901 requirements are met, the DT included explicit references to IBR-specific data and parameters and pointed to the uniform framework through an alignment between planning and operations models. These requirements are only as applicable, and the DT does not find this to be administrative in nature for reliability needs. The DT worked to strengthen Requirement R1 in that it is not adding any new data collection from what is already deemed necessary.

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	

Comment
TOP-003 and IRO-010 Requirements to gather data that is not needed or utilized by the RC or BA become an administrative burden to track and assess. Other expenses to store the unnecessary data highlight the ineffectiveness of costs.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The DT reviewed existing IRO-010 and TOP-003 versions and found that both standards had broad requirements language that encompassed generation and storage resources, including IBR. Nevertheless, to ensure no ambiguity that FERC Order 901 requirements are met, the DT included explicit references to IBR-specific data and parameters and pointed to the uniform framework through an alignment between planning and operations models. These requirements are only as applicable, and the DT does not find this to be administrative in nature for reliability needs. The DT worked to strengthen Requirement R1 in that it is not adding any new data collection from what is already deemed necessary.

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

ACES does not believe the proposed modifications to MOD-032-2 represent the most cost-effective means of addressing FERC Directive 901. ACES asserts that the DT remains well within the scope of the directive in establishing a threshold to define “material affect.” By proactively setting a threshold of 20 MVA or greater in aggregate and requiring mandatory reporting for inverter-based resource - distributed energy resources (IBR-DER) with individual nameplate ratings of 5 MVA or greater, the DT can satisfy the intent of the Standard Authorization Request (SAR) while enabling a more economically viable implementation for industry stakeholders.

This approach allows entities to provide more meaningful and actionable data to the Planning Coordinator (PC) and Transmission Planner (TP), without incurring the significant compliance, legal, and accounting burdens associated with parsing and aggregating distribution-level interconnection agreements for small-scale IBR-DER units. Distribution providers would be able to leverage existing billing and metering systems to determine aggregate IBR-DER values and assess applicability under MOD-032-2 Requirement R2.1. This methodology is expected to offer a more practical and cost-effective path to compliance with FERC Directive 901.

Furthermore, the resulting data provided to the PC/TP would likely be of higher quality, as individual nameplate data for IBR-DER units rated at or above 5 MVA is more readily obtainable and verifiable. This targeted reporting would yield more reliable data than estimates derived from significantly smaller IBR-DER units. Finally, this approach would reduce the volume of data sets requiring manual review and integration by the PC/TP, thereby lowering resource demands and improving overall cost efficiency.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. As referenced in the Technical Rationale, NERC has published a study concluding that a 0 MW threshold is appropriate for data collection purposes. The DT concluded that even if a threshold was applied, data would still need to be collected to verify and ensure that a threshold was not being exceeded. Further, the DT determined that there is no strong technical justification for any particular universal DER threshold. In fact, any universal threshold would likely be inappropriate for many areas, so the DT created the flexibility for the PC/TP to make this determination for their local region. The proposed solution in the ACES comment does not address the

potential aggregate impact of thousands of kW-scale DERs. The DT contends that the FERC concern is less about getting more detailed models for 5 MW (and larger) facilities (as most transmission planners are unlikely to utilize such detailed modeling for distribution-connected facilities) but being aware of and appropriately representing aggregations of smaller facilities at the T-D interface. Material affect - see Consideration of FERC Directive. The DT stated: "Determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk Power System, requires engineering judgment and is not something that would be appropriate to precisely specify in a reliability standard. Thus, Attachment 1 footnote 7 was added to explicitly allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas." There is nothing that precludes ACES from identifying a threshold needed based on how MOD-032 has been drafted (See footnote 7). Therefore, because you can set your threshold, the drafting team does not agree that this presents a cost effective issue.	
Joshua Phillips - Southwest Power Pool, Inc. (RTO) - 2	
Answer	No
Document Name	
Comment	
SPP supports the comments provided by the IRC Standards Review Committee	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to IRC SRC.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

For MOD-032, there will be an administrative burden due to the need to:

· Develop a methodology and process for the estimation process for data that is not available to the TO. This would not be a one-time effort but year over year as DER increases.

· Increased outreach to other entities such as registered DPs for their best estimate on the modeling.

· There will be a need to increase personnel to do the work that is already a tight market for applicable employees.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Per FERC Order 901 P 103: "We recognize that there may be limitations on the ability of certain transmission owners to provide all data about unregistered IBRs that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System. Likewise, there may be limitations on the ability of certain distribution providers to provide all data about IBR-DERs in the aggregate that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System." Based on this information, it was determined that an estimation is better than nothing, and this is only needed if the functional entity is unable to gather data needed from the respective entity.

The DT acknowledges that new requirements to collect data not currently collected will come with increased burdens. The DT did the best it could to provide flexibility and minimize administrative burdens on entities while satisfying the directives from the FERC Order.

In addition, MOD-032-2 does not mandate Transmission Owner responsibility for DER data. Requirement R1 allows the flexibility for the PC/TP to determine the best entity to provide DER data in their local area (with the understanding that certain markets may provide better alternative sources for DER data - see TR for some examples).

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

For MOD-032, this will be an administrative burden due to the need to:

{C}· Develop a methodology and process for the estimation process for data that is not available to the TO. This would not be a one-time effort but year over year as DER increases.

{C}· Increased outreach to other entities such as registered DPs for their best estimate on the modeling.

{C}· There will be a need to increase personnel to do the work that is already a tight market for applicable employees.

There are no foreseen issues with IRO-010-6 or TOP-003-8.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Per FERC Order 901 P 103: "We recognize that there may be limitations on the ability of certain transmission owners to provide all data about unregistered IBRs that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System. Likewise, there may be limitations on the ability of certain distribution providers to provide all data about IBR-DERs in the aggregate that Bulk-Power System transmission planners and operators may need for the reliable operation of the Bulk-Power System." Based on this information, it was determined that an estimation is better than nothing, and this is only needed if the functional entity is unable to gather data needed from the respective entity.

When new requirements are created, there is going to come change in work. The DT did the best it could to ensure administrative burdens on entities outside of what is required from the FERC Order.

In addition, it may not end up being the TOs responsibility based on the outcome of Requirement R1. See TR. There is DER in certain markets that provides other data, etc.

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to WPP.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
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	
Southern Company agrees the modifications for the proposed reliability standards address the scope of the SAR in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Thank you.	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathon Flores - Los Angeles Department of Water and Power - 1,3,5,6	
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	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
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	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
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	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
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	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott Thompson - TXNM Energy - 3	
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	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Goddard - DTE Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
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	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, 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	
Wesley Yeomans - New York State Reliability Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	

Comment	
No comment on cost effectiveness as Duke Energy's focus is on reliability of the BES.	
Likes 0	
Dislikes 0	
Response	
Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	

Likes 0	
Dislikes 0	
Response	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE has no comment.	
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 will not comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed ERO Unacceptable Models List? If you do not agree, please provide alternative language and explain the rationale that, if made, would result in your support.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
NIPSCO does not believe that models on the unapproved list should be allowed to be used, even if technical justification is provided for doing so. There are legitimate reasons why these models should not be used, so a path for their potential inclusion should not be provided.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on feedback received in draft 1, many entities felt there are certain situations where a model that is unacceptable today, may be the best fit for an older unit, etc. The DT decided to provide flexibility, allowing an unacceptable model to be submitted in conjunction with a technical rationale justifying the use of that model. However, the DT believes that there in nothing in MOD-032 that would prevent a PC/TP from implementing more stringent data reporting requirements (e.g. not allowing any models from the UML) if deemed appropriate for their area.	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	

Transmission Planners cannot submit models to the regional case build process that are not approved models. By allowing this, we will create a very costly and unproductive loop where DER models that are unacceptable keep getting sent back from the TP to the DP until they are acceptable. A standalone methodology would be better as mentioned by other participants.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. MOD-032 allows flexibility in what models need to be collected, but in PC/TP procedures, it would be recommended that the TP/PC be familiar with the MMWG, ERAG, WECC requirements and incorporate them as needed.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The act of renaming is creating a new list, not just replacing the old, acceptable model list. The ERO Unacceptable Models List does not have industry consensus and was not established through the standards process. TVA does not believe it should be referenced in a compliance standard. In its place, TVA recommends specifications for standard models (where appropriate and available), user-written models (where appropriate and with adequate documentation), and other models (when no alternative is available and requiring justification for use).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In approval of the MOD-032-2 Reliability Standard, The Unacceptable Models List Maintained by the ERO did go through the development process as a starting point for this document. Any modifications need to follow the process provided in the MOD-032 standard. This document originally came out of the SAMs group and is a well-known document throughout industry. In addition, reasons as to why unacceptable models are added to the Unacceptable Models List are located in chapter 2 of the UML document. Lastly, Additions to or removals from the UML can be made through the process outlined in MOD-032.	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP does not believe that models on the unapproved list should be allowed to be used, even if technical justification is provided for doing so. There are legitimate reasons why these models should not be used, so a path for their potential inclusion should not be provided.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on feedback received in draft 1, many entities felt there are certain situations where a model that is unacceptable today, may be the best fit for an older unit, etc. The DT decided to provide flexibility, allowing an unacceptable model to be submitted in conjunction with a technical rationale justifying the use of that model. However, the DT believes that there in nothing in MOD-032 that would prevent a PC/TP from implementing more stringent data reporting requirements (e.g. not allowing any models from the UML) if deemed appropriate for their area.	
Adrian Harris - Adrian Harris On Behalf of: Kirsten Rowley, Midcontinent ISO, Inc., 2; - Adrian Harris, Group Name RTO/ISO Council Standard Review Committee	
Answer	No
Document Name	2022-02_Unofficial_Comment_Form SRC.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

EEI supports the ERO's Unacceptable Model List.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
It does not appear that the language of the MOD-032 Supporting Document: Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO) has considered the role of the AMWG under ERAG for building and maintaining the Eastern Interconnection models. I believe this document is more formal, and describes a more centralized process for the maintenance of the official Unacceptable Models List. It does not appear that the language provided by the SDT aligns with the charter of the AMWG, unless the AMWG fits into the general description of the "ERO Staff" under items 2 and 3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. A PC/TP could implement a more stringent requirement related to unacceptable models (e.g., not allowing them even with a rationale, or requiring the submission of a specific set of models) to align with a higher level modeling group such as the AMWG. Thus, it does not appear that MOD-032-2 would conflict with such a group, though the DT acknowledges that it would be beneficial for AMWG policies to align with the ERO document and MOD-032-2. If justification of an UM needing to be removed from the UML, can be provided through the process outlined in MOD-032. Additions to or removals from the UML can be made through the process outlined in MOD-032. In addition, the ERAG and MMWG perform the MOD-032 designee functions per the process within the EASTERN INTERCONNECTION REGIONAL ENTITY AGREEMENT that is located on the MMWG website.	

If an unacceptable model is submitted without a technical rationale, it would be a compliance violation for the model submitter. Similar to any and every model that is submitted (even an "acceptable" model that is parameterized poorly and creates initialization or simulation issues), the TP and PC must make a determination of whether it can be used in a case-building process (with the acknowledgement that resolution of a model issue may not align with the deadline to finalize a base case). This may be completely separate from pursuing a technical concern under R3. MOD-032-2 does not specify any requirements for replacing or modifying unacceptable models, because that process is very dependent on the situation and requires engineering judgment (and finalizing a base case with the "unacceptable" model may end up being the best option).

In addition, the ERAG and MMWG is the MOD-032 designee per the process within the EASTERN INTERCONNECTION REGIONAL ENTITY AGREEMENT and is located on the MMWG website.

See link to agreement language above. https://www.rfirst.org/wp-content/uploads/2023/10/EI-Regional-Entity-Agmt-Final-Signed.pdf

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the ERO's Unacceptable Model List.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes

Document Name	
Comment	
Portland General Electric (PGE) aligns with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the ERO's Unacceptable Model List.	
Likes 0	
Dislikes 0	
Response	
Thank you 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 EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
USV agrees with the ERO Unacceptable Model List but requests that the reason for models being unacceptable be made public to provide clarity on Requirement R2.3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The ERO Unacceptable Model is public on the NERC website under reports. In addition, the UML was posted alongside the standard documents for the postings. Lastly, reasons as to why unacceptable models are added to the Unacceptable Models List are located in chapter 2 of this document.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	

SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CEHE has no further comment.	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with the proposed ERO Unacceptable Models List.	
Likes 0	

Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
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	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Wesley Yeomans - New York State Reliability Council - 10	
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	
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; John Nierenberg, 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	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
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	
Brittany Millard - Lincoln Electric System - 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	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
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	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Goddard - DTE Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 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	
Ben Hammer - Western Area Power Administration - 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	
Scott Thompson - TXNM Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
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	
Hayden Maples - Hayden Maples 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; - Hayden Maples	
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	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
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	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karina Valencia - Karina Valencia On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Karina Valencia	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kelly Heims - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathon Flores - Los Angeles Department of Water and Power - 1,3,5,6	
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	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Provide any additional comments for the drafting team to consider, if desired.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP recommends that the Attachment “Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)” be removed from the MOD-032 standard, and added instead to the ERO Unacceptable Models List document.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Based on comments received during draft 1, multiple commenters requested the Unacceptable Models Listed Maintained by the ERO go through the standards development process. By adding the process for this respective document to MOD-032 allows that process to take place. Therefore, based on comments received in this draft, majority of industry is in agreement with the process being a supporting document to the MOD-032 standard.	
Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
We appreciate the time and effort put in by the Drafting Team on this project and commend them for finding the best resolution for addressing the FERC 901 directive.	
Likes 0	

Dislikes 0	
Response	
Thank you.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy believes MOD-032-2 R2.2 creates Requirement duplication by providing models already outlined and required in NERC MOD-026. The duplication creates the potential for non-compliance in two separate Standards, while also introducing overlapping documentation and reporting and possibly conflicting deadlines. Because MOD-032-2 R2.2 results in increased risk of Non-Compliance for the applicable entities, Duke Energy recommends R2.2 be deleted from the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC Order No. 901 directives require collection of accurate models for use in both planning and operations. Within the paradigm of NERC standards, data collection requirements are established under MOD-032 while model accuracy is ensured through model verification and validation requirements under MOD-026. Joint discussions between the Project 2022-02 and 2020-06 teams concluded that the most effective way to satisfy the FERC directive was for MOD-032 to require provision of "the models accepted by the Transmission Planner under MOD-026, where such models are available".	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FirstEnergy offers no additional comments.	
Likes 0	
Dislikes 0	
Response	
Kelly Heims - Central Iowa Power Cooperative - 1	
Answer	
Document Name	
Comment	
Central Iowa Power Cooperative supports the comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to ACES.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
TVA appreciates the efforts by the standard draft team. Regarding Attachment 1 Dynamics 10.b, this data could be difficult to accurately model for situations where the DP will often reconfigure their systems and move DERs between feeders. TVA recommends removing 10.b.	

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Representing the impact of UVLS and UFLS on DER (i.e., tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.

Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3

Answer	
Document Name	

Comment

We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the

entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data, but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1. This could allow NYISO to directly connect data from DERs within the area.

As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."

P. 106: "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	
Document Name	
Comment	

We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data, but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1. This could allow NYISO to directly connect data from DERs within the area.

As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."

P. 106: "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect

the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5

Answer	
Document Name	

Comment
We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data, but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1. This could allow NYISO to directly connect data from DERs within the area.

As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."

P. 106: "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	
Document Name	
Comment	

We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.
There is nothing that precludes an entity from requesting DER data from unregistered distribution providers. If an entity can show that they made the effort to contact the unregistered entity and no response was received, then Requirement R2 Part 2.1 would take place where the entity would complete an estimation. This comment goes against FERC Order 901 and what has been directed of industry. It is important for reliability purposes that unregistered IBRs that are connected to the grid are identified for reliability purposes. In addition, TO has been listed as one of the typical entities for providing DER data, but would not have to be assigned based on the flexibility provided via Requirement R1 Part 1.1. This could allow NYISO to directly connect data from DERs within the area.

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Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Alain Mukama On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Alain Mukama	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thomas Brinckman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	

Comment	
CEHE supports EEI comments as proposed.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
SCL supports Western Power Pool's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	
Document Name	
Comment	

Eversource suggests defining or modifying the phrase “standard library models” in MOD-032 R1.4.1 to make it less application-specific as this phrase has no set meaning in some software.

Eversource suggests the removal of Footnote 5 from Attachment 1 of MOD-032. This phrase provides little to no value and only provides speculation whereas Requirement R1.1 already defines a mechanism to assign ownership. In some regions, these data points may not be provided by the TO, but the footnote seems to imply that it should.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. FERC Order 901 directs NERC to develop reliability standards that require “the use of approved industry generic library IBR models”. However, pre-defining a limited set of models (i.e., a library of models) that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To align with industry practices while addressing the directives of the FERC Order, the DT referenced standard library models incorporated within software as well as usability requirements for user-defined models (where accepted) in Requirement R1, Part 1.4, rather than defining an inclusive model library.

Footnote 5 indicates that the PC/TP data requirements and reporting procedures need to account for IBRs that are not DERs and do not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. It also indicates that the TO is typically responsible for such data. The DT was attempting to address FERC Order 901 with regards to the TO and providing clarity to industry on the "typical" entity, without restricting applicability based on other comments received over the course of this project.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

The 2022-02 Technical Rationale (TR) in its IRO-010-6 and TOP-003-8 section (page 14) seems to indicate that modifications were made to "add reference to MOD-032", however the only reference to MOD-032 has been added in the 2022-02 TR via the clarification on the intent behind the revised R1 Part 1.5.3 (and R2 Part 2.5.3 for TOP-003 only). Please clarify if the intention is to add a MOD-032 reference to Standards as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the updated TR, which addresses your comments.	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
The Reliability Standards Committee (RSC) of NPCC supports the proposed draft standard.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to NPCC.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,5	
Answer	
Document Name	
Comment	

To reiterate, TAL believes the intent of 2.5.3 is well intended, but that this standard does not belong in TOP-003-8, R2. R2 is a BA standard. R2.5.3 seems to be a modeling standard. R2.5.3 seems redundant with respect to other modeling and commissioning standards being developed. TAL believes that in all practical sense, this must be accomplished in planning standards, which come into play during interconnection studies, model verification and validation processes and commissioning.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Representing the impact of UVLS and UFLS on DER (i.e., tripping DER along with the load that is tripped) is essential to designing effective UVLS and UFLS programs. Further details are included in the published Reliability Guideline and White Paper that are referenced in the Technical Rationale. If this item is excluded from MOD-032, industry will eventually need to grapple with modifying processes for gathering DER data to address this issue (a draft SAR to modify PRC-006 to address DER impacts on UFLS program design is being considered under the RSTC and points to addressing this issue if not addressed under Project 2022-02). The DT believes that establishing processes for developing and collecting this information in conjunction with other DER data under MOD-032 is the most efficient approach.

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	

Comment
None

Likes 0	
Dislikes 0	

Response

Kera Schwartz - Southern Indiana Gas and Electric Co. - 2,3,4 - RF	
Answer	
Document Name	
Comment	
Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) supports EEI's comments on the revisions.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Scott Thompson - TXNM Energy - 3	
Answer	
Document Name	
Comment	
Regional Entities may or may not have a list of acceptable and unacceptable models, how does the STD take into account certain unaceptable models vs acceptable per RE?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. NERC maintains a designee agreement for the entities designated to build Interconnection-wide cases as seen in R4 of MOD-032. These agreements allow for the entities to build a separate list that is more restrictive if they desire. MOD-032 allows flexibility in what types of models need to be collected. It would be recommended that the TP/PC be familiar with the requirements of	

entities designated to build Interconnection-wide cases (e.g. MMWG, ERAG, WECC) and incorporate them into their data collection procedures as needed.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	Project 2022-02 _ EEI Final Draft Comments _ MOD-032 IRO-10 TOP-003 Draft 2_ Rev. 0i _ 9_05_2025.docx
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Please see DT's response to EEI.	
Chris Shultz - Seattle City Light - 5	
Answer	
Document Name	
Comment	
Support Western Power Pool Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to WPP.	
Ben Hammer - Western Area Power Administration - 1	

Answer	
Document Name	
Comment	
The currently proposed MOD-032-2 Standard does not clearly identify which generations assets the standard is applicable to. We suggest that the following clarifying addition be added to 4.1.3 of the Applicability section of MOD-032-2 4.1.3 Generator Owner – Category 1 and 2	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Under the proposed definition of Generator Owner adopted by the NERC Board in August 2025 and pending FERC approval, the term "Generator Owner" as used in MOD-032-2 would include owners of both Category 1 and Category 2 assets. In MOD-032-2's case, it refers to both and no changes need to be made.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	

Answer	
Document Name	
Comment	
NIPSCO recommends that the Attachment “Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)” be removed from the MOD-032 standard, and added instead to the ERO Unacceptable Models List document.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Multiple commenters to draft 1 requested that the Unacceptable Models List Maintained by the ERO go through the standards development process. Including the process for updating this document within MOD-032 ensures that any changes to the Unacceptable Models list follow a process that is established through the standards development process. Based on comments received in this draft, a majority of industry is in agreement with this compromise approach.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to share comments and suggestions. ACES realizes this has been a huge undertaking and we appreciate all the time and effort the DT has put into executing the FERC 901 Directive under such a short timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	2022-02_Unofficial_Comment_Form_Additional_Posting_NSRF v9.10.2025.docx
Comment	
The MRO NSRF encourages clear and consistent identification of which generation assets standards are applicable to. The currently proposed MOD-032-2 Reliability Standard Applicability Section does not clearly identify those entities. While we recognize the proposed definition of GO includes both Category 1 & 2, the MRO NSRF proposes that the following be added to 4.1.3 of the Applicability Section of MOD-032-2 (shown in boldface): 4.1.3 Generator Owner - **Category 1 and 2**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Under the proposed definition of Generator Owner adopted by the NERC Board in August 2025 and pending FERC approval, the term "Generator Owner" as used in MOD-032-2 would include owners of both Category 1 and Category 2 assets. In MOD-032-2 case, it refers to both and no changes need to be made.	
Brittany Millard - Lincoln Electric System - 5	
Answer	
Document Name	
Comment	
R1.5.3 should be removed from TOP-003-8. Model submissions don’t belong in the data spec.	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Please see updates made to TOP and IRO to provide non-substantive clarity for the RC, BA, and TOP.

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	

Response

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
MEC agrees with the comments of the MRO NSRF. However, none of these concerns rise to the level of a negative ballot for MEC. Consideration and clarifications around the concerns expressed in the MRO NSRF comments would make for a better Reliability Standard if there is opportunity for substantive revisions.	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
We support the comments from the MRO NSRF and desire that the comments are considered, but feel the standard is sufficient for an affirmative vote.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	
DP's likely do not have in-house expertise available to comply with providing dynamic models of aggregated DER resources; even estimated modeling when certified modeling is unavailable due to regulatory limitations. NERC and the drafting team should consider resource availability of the consultants who will be required to support DP's in the new compliance obligation as implementation plans are determined.	
Likes 0	

Dislikes 0	

Response

Thank you for your comment. The level of detail is determined locally by the PC/TP, but it is expected that TPs and PCs will need to work together with TOs and DPs to establish feasible processes and formats for collecting DER data. Those processes could specify the provision of dynamic models or basic data that planners could translate into dynamic models. The SPIDERWG has published several Reliability Guidelines related to the collection of DER data and parameterizing models (such as the DER_A model) to represent aggregate DER. The DT intentionally refrained from specifying provision of "dynamic models" for DER, but instead refers to "aggregate DER data". That data must represent certain capabilities in accordance with attachment 1, but attachment 1 alternatively allows for collection of "information that can be used to infer those items for modeling purposes".

Wesley Yeomans - New York State Reliability Council - 10

Answer	
Document Name	

Comment

We do not agree that the TO is the appropriate entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system. In the NY area, the most appropriate entity would be the NYISO; this requirement should be moved to the BA/PC. The NYISO is in a better position to require entities to submit the required data when they join the market; individual TOs cannot. The NYISO has processes for maintaining the necessary system representation data to comply with FERC, NERC, NPCC, and NYSRC requirements.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. As mentioned above, please see FERC Order No. 901 P 105 and 106, which states, "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in

the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reminder
Standards Announcement
Project 2022-02 Uniform Modeling Framework for IBR

Additional Ballots and Non-binding Polls Open through September 10, 2025

Now Available

Additional ballots for **Project 2022-02 Uniform Modeling Framework for IBR** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern Wednesday, September 10, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and Information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- Implementation Plan

The 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, Jordan Mallory (via email) or at 470-479-7538. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR 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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Formal Comment Period Open through September 10, 2025

Now Available

A 34-day formal comment period for **Project 2022-02 Uniform Modeling Framework for IBR**, is open through **8 p.m. Eastern, Wednesday, September 10, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and Information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- 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.

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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.*
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- *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 28 - September 10, 2025**.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 470-479-7538. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-02 Uniform Modeling Framework for IBR observer list” in the Description Box.



North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 AB 2 ST
Voting Start Date: 8/28/2025 12:01:00 AM
Voting End Date: 9/10/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 257
Total Ballot Pool: 280
Quorum: 91.79
Quorum Established Date: 9/10/2025 2:50:16 PM
Weighted Segment Value: 73.77

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	44	0.688	20	0.313	0	7	1
Segment: 2	7	0.6	6	0.6	0	0	0	0	1
Segment: 3	66	1	43	0.741	15	0.259	0	2	6
Segment: 4	14	1	9	0.692	4	0.308	0	0	1
Segment: 5	68	1	33	0.647	18	0.353	0	8	9
Segment: 6	47	1	30	0.732	11	0.268	0	2	4
Segment: 7	0	0	0	0	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:	280	6.1	169	4.5	69	1.6	0	19	23

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted

5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
3	AES - Indianapolis Power and Light Co.	Sing Tay		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A

3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	Third-Party Comments
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted

6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	Salt River Project	Israel Perez	Timothy Singh	Negative	Comments Submitted
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Timothy Singh	Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
5	Constellation	Marie Potter		Affirmative	N/A

3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Comments Submitted
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
5	Orsted Americas	Keith Smith		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	AEP	Randy Calhoun		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Third-Party Comments
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Third-Party Comments
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A

1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Negative	Third-Party Comments
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Third-Party Comments
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A

3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A

6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	Comments

				Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday	Affirmative	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 AB 2 ST
Voting Start Date: 8/28/2025 12:01:00 AM
Voting End Date: 9/10/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 256
Total Ballot Pool: 281
Quorum: 91.1
Quorum Established Date: 9/10/2025 2:53:52 PM
Weighted Segment Value: 86.15

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	73	1	56	0.903	6	0.097	0	8	3
Segment: 2	7	0.6	1	0.1	5	0.5	0	0	1
Segment: 3	66	1	54	0.931	4	0.069	0	2	6
Segment: 4	14	1	13	1	0	0	0	0	1
Segment: 5	68	1	45	0.918	4	0.082	0	10	9
Segment: 6	47	1	37	0.902	4	0.098	0	2	4
Segment: 7	0	0	0	0	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:	281	6.1	211	5.255	23	0.845	0	22	25

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A

1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Sing Tay		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A

5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	Salt River Project	Israel Perez	Timothy Singh	Negative	Comments Submitted
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy	Negative	Comments

			Singh		Submitted
1	Salt River Project	Laura Somak	Timothy Singh	Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A

5	Orsted Americas	Keith Smith		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		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
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
6	AEP	Randy Calhoun		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A

1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A

1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A

3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A



Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 AB 2 ST
Voting Start Date: 8/28/2025 12:01:00 AM
Voting End Date: 9/10/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 257
Total Ballot Pool: 281
Quorum: 91.46
Quorum Established Date: 9/10/2025 2:54:08 PM
Weighted Segment Value: 82.56

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	73	1	55	0.887	7	0.113	0	9	2
Segment: 2	7	0.6	1	0.1	5	0.5	0	0	1
Segment: 3	66	1	51	0.895	6	0.105	0	3	6
Segment: 4	14	1	12	0.923	1	0.077	0	0	1
Segment: 5	68	1	43	0.878	6	0.122	0	10	9
Segment: 6	47	1	35	0.854	6	0.146	0	2	4
Segment: 7	0	0	0	0	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:	281	6.1	202	5.036	31	1.064	0	24	24

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A

1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Sing Tay		None	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A

3	Omaha Public Power District	David Heins		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	Salt River Project	Israel Perez	Timothy Singh	Negative	Comments Submitted
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A

10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Timothy Singh	Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A

3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Orsted Americas	Keith Smith		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		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
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
6	AEP	Randy Calhoun		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A

3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A

3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Abstain	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 Implementation Plan AB 2 OT
Voting Start Date: 8/28/2025 12:01:00 AM
Voting End Date: 9/10/2025 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 251
Total Ballot Pool: 275
Quorum: 91.27
Quorum Established Date: 9/10/2025 3:02:16 PM
Weighted Segment Value: 76.84

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	73	1	50	0.781	14	0.219	1	6	2
Segment: 2	7	0.5	2	0.2	3	0.3	0	1	1
Segment: 3	64	1	46	0.836	9	0.164	0	3	6
Segment: 4	13	1	9	0.75	3	0.25	0	0	1
Segment: 5	67	1	36	0.766	11	0.234	0	10	10
Segment: 6	45	1	32	0.8	8	0.2	0	2	3
Segment: 7	0	0	0	0	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	1	1
Totals:	275	5.9	179	4.534	48	1.366	1	23	24

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A

1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Sing Tay		None	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	Third-Party Comments
6	Tennessee Valley Authority	Jeffrey Powell		Negative	Comments Submitted

4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	Salt River Project	Israel Perez	Timothy Singh	Negative	Comments Submitted
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A

3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	Comments Submitted
1	Salt River Project	Laura Somak	Timothy Singh	Negative	Comments Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	Third-Party Comments
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
					No

1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Negative	Comment Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
5	Orsted Americas	Keith Smith		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		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
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
6	AEP	Randy Calhoun		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Comments Submitted

5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell	Jennifer Sieg	Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A

3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments

3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	Third-Party Comments
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Comments Submitted
					Comments

3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci	Negative	Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday	Affirmative	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 | Non-binding Poll AB 2 NB
Voting Start Date: 8/28/2025 12:01:00 AM
Voting End Date: 9/10/2025 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 237
Total Ballot Pool: 260
Quorum: 91.15
Quorum Established Date: 9/10/2025 3:01:39 PM
Weighted Segment Value: 71.94

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	70	1	39	0.722	15	0.278	13	3
Segment: 2	6	0.5	5	0.5	0	0	1	0
Segment: 3	63	1	37	0.755	12	0.245	7	7
Segment: 4	13	1	8	0.667	4	0.333	0	1
Segment: 5	59	1	26	0.65	14	0.35	13	6
Segment: 6	43	1	23	0.719	9	0.281	6	5
Segment: 7	0	0	0	0	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	0.4	3	0.3	1	0.1	1	1
Totals:	260	5.9	141	4.313	55	1.587	41	23

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Negative	No Comment Submitted
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	No Comment Submitted
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	No Comment Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	No Comment Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	No Comment

					Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	No Comment Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Negative	No Comment Submitted
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	No Comment Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	No Comment Submitted
3	AES - Indianapolis Power and Light Co.	Sing Tay		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	No Comment Submitted
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	No Comment Submitted
4	Austin Energy	Tony Hua	Hayden	Affirmative	N/A

1	Evergy	Kevin Frick	Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	No Comment Submitted
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	No Comment Submitted
6	Tennessee Valley Authority	Jeffrey Powell		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	No Comment Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	No Comment Submitted
3	Omaha Public Power District	David Heins		Negative	No Comment Submitted
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	No Comment Submitted
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Salt River Project	Israel Perez	Timothy Singh	Negative	No Comment Submitted

3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Negative	No Comment Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	No Comment Submitted
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	No Comment Submitted
1	Salt River Project	Laura Somak	Timothy Singh	Negative	No Comment Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	AEP	Thomas Foltz		Negative	No Comment Submitted
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	No Comment Submitted
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Negative	No Comment Submitted

6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	No Comment Submitted
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	No Comment Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	No Comment Submitted
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Negative	No Comment Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	No Comment Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	No Comment Submitted

5	Dairyland Power Cooperative	Tommy Drea		Negative	No Comment Submitted
6	AEP	Randy Calhoun		Negative	No Comment Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Negative	No Comment Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Negative	No Comment Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
6	Duke Energy	John Sturgeon		Negative	No Comment Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	No Comment Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	No Comment Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A

6	New York Power Authority	Shelly Dineen	Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce	Abstain	N/A
5	New York Power Authority	Zahid Qayyum	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger	None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino	Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson	Affirmative	N/A
1	Seattle City Light	Michael Jang	Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio	Negative	No Comment Submitted
5	Edison International - Southern California Edison Company	Selene Willis	Affirmative	N/A
1	M and A Electric Power Cooperative	William Price	Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham	Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu	Affirmative	N/A
1	Western Area Power Administration	Ben Hammer	Negative	No Comment Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith	Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny	Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir	Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong	Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott	Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie	Affirmative	N/A
1	Duke Energy	Katherine Street	Negative	No Comment Submitted
3	JEA	Marilyn Williams	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell	Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry	Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier	Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans	Negative	No Comment Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	N/A
3	Exelon	Kinte Whitehead	Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy	Affirmative	N/A
5	Lincoln Electric System	Brittany Millard	Abstain	N/A
1	Lincoln Electric System	Josh Johnson	Abstain	N/A
3	Lincoln Electric System	Sam Christensen	Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins	Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup	Affirmative	N/A
				No

1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comment Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	No Comment Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	No Comment Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	No Comment Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	No Comment Submitted
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	No Comment Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	No Comment Submitted
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	No Comment Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	No Comment Submitted
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	No Comment Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	No Comment Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A

Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 | Non-binding Poll AB 2 NB
Voting Start Date: 8/28/2025 12:01:00 AM
Voting End Date: 9/10/2025 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 236
Total Ballot Pool: 261
Quorum: 90.42
Quorum Established Date: 9/10/2025 3:07:07 PM
Weighted Segment Value: 93.26

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	50	0.943	3	0.057	13	5
Segment: 2	6	0.4	1	0.1	3	0.3	2	0
Segment: 3	63	1	46	0.939	3	0.061	7	7
Segment: 4	13	1	12	1	0	0	0	1
Segment: 5	59	1	37	0.949	2	0.051	14	6
Segment: 6	43	1	30	0.938	2	0.063	6	5
Segment: 7	0	0	0	0	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	0.4	4	0.4	0	0	1	1
Totals:	261	5.8	180	5.268	13	0.532	43	25

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings	Michael Moltane	Allie Gavin	Affirmative	N/A

	Corporation				
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Sing Tay		None	N/A
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise	Affirmative	N/A

			Sanchez		
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	No Comment Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Salt River Project	Israel Perez	Timothy Singh	Negative	No Comment Submitted
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	No Comment Submitted
1	Salt River Project	Laura Somak	Timothy Singh	Negative	No Comment Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A

2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	No Comment Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A

4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
6	AEP	Randy Calhoun		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	No Comment Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		None	N/A
3	Edison International - Southern California Edison	Romel Aquino		Affirmative	N/A

	Company				
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	No Comment Submitted

3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	No Comment Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
					No

1	Basin Electric Power Cooperative	David Rudolph		Negative	Comment Submitted
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	No Comment Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A



Ballot Results

Comment: View Comment Results
Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 | Non-binding Poll AB 2 NB
Voting Start Date: 8/28/2025 12:01:00 AM
Voting End Date: 9/10/2025 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 235
Total Ballot Pool: 260
Quorum: 90.38
Quorum Established Date: 9/10/2025 3:07:59 PM
Weighted Segment Value: 91.53

Actions

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	49	0.942	3	0.058	15	4
Segment: 2	6	0.4	1	0.1	3	0.3	2	0
Segment: 3	62	1	44	0.936	3	0.064	8	7
Segment: 4	13	1	11	0.917	1	0.083	0	1
Segment: 5	59	1	35	0.921	3	0.079	14	7
Segment: 6	43	1	29	0.906	3	0.094	6	5
Segment: 7	0	0	0	0	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	0.4	4	0.4	0	0	1	1
Totals:	260	5.8	173	5.122	16	0.678	46	25

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	No Comment Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings	Michael Moltane	Allie Gavin	Affirmative	N/A

	Corporation				
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	No Comment Submitted
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Sing Tay		None	N/A
6	Black Hills Corporation	Josh Schumacher		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	No Comment Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	No Comment Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Omaha Public Power District	Kayleigh		Affirmative	N/A

		Wilkerson			
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Abstain	N/A
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	No Comment Submitted
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Salt River Project	Israel Perez	Timothy Singh	Negative	No Comment Submitted
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	No Comment

					Submitted
1	Salt River Project	Laura Somak	Timothy Singh	Negative	No Comment Submitted
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	No Comment Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Abstain	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A

3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
6	AEP	Randy Calhoun		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A

5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	No Comment Submitted
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A

5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	No Comment Submitted
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	No Comment Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	No Comment Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A

5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	No Comment Submitted
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	No Comment Submitted
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	No Comment Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	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

MOD-032-2 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
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(The above was Posted under IRPTF SAR pre–Order No. 901)	
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Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

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):

Distributed Energy Resource (DER): A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** Data for Power System Modeling and Analysis

2. **Number:** MOD-032-2

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Generator Owner

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation;

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data that is responsive to the technical concern.

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

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

   - Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. **Compliance Monitoring and Enforcement Program:** Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

3. **Potential Noncompliance (PNC) Abeyance Period:**
Potential Noncompliance (PNC) Abeyance Period: For a period of two years following the phased-in compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. "Good faith" in this context refers to a sincere intention to

comply with Reliability Standard MOD-032-2 Requirement R2 Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. For example, the CEA may not pursue compliance enforcement actions during this period for entities who submit estimated data and include the supporting data explanation and methods used as detailed in Requirement R2 Part 2.1 in a timely manner. The CEA may pursue actions against entities who do not submit data with supporting explanation and methods in a timely manner. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.
R2.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not

	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

	Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission

	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data

	in the format specified by the ERO or its designee.	the format specified by the ERO or its designee.	required data in the format specified by the ERO or its designee.	in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List

MOD-032-2 – ATTACHMENT 1
Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in Interconnection-wide cases. The joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify entity responsibility and data flow processes. The typical functional entity[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be identified by the bus number, name, and/or identifier that is assigned in conjunction with the Planning Coordinator, Transmission Owner, or Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
1. Each bus [TO] a. Nominal voltage b. Area, zone and owner 2. Aggregate Demand[3] [DP] a. Real and reactive power* b. In-service status* 3. Generating and storage units[4] [GO, TO[5], RP (for future planned resources only)] a. Real power capabilities - gross maximum and minimum values b. Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. Regulated bus* and voltage set point* (as typically provided by the TOP) e. Machine MVA base	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[3] [DP] 6. Wind plant model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control 8. Static Var Systems and FACTS [GO, TO, DP] 9. DC System Models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive sequence data b. Negative sequence data c. Zero sequence data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
f. Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. Generator type (hydro, wind, fossil, solar, nuclear, etc.) h. In-service status* 4. AC Transmission Line or Circuit [TO] a. Impedance parameters (positive sequence) b. Susceptance (line charging) c. Ratings (normal and emergency)* d. In-service status* 5. DC Transmission Systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. Nominal voltages of windings b. Impedance(s) c. Tap ratios (voltage or phase angle)* d. Minimum and maximum tap position limits e. Number of tap positions (for both the ULTC and NLTC) f. Regulated bus (for voltage regulating transformers)* g. Ratings (normal and emergency)* h. In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. Admittances (MVars) of each capacitor and reactor b. Regulated voltage band limits* (if mode of operation not fixed) c. Mode of operation (fixed, discrete, continuous, etc.) d. Regulated bus* (if mode of operation not fixed) e. In-service status* 8. Static Var Systems [TO] a. Reactive limits b. Voltage set point* c. Fixed/switched shunt, if applicable d. In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1)	a. parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
b. Real power capability c. DER type (solar, battery, diesel generator, etc.) 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. (Note: This may be impacted by an aggregation threshold for DER specified under footnote 7.) A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider’s system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner’s system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This Supporting Document describes the process by which changes may be made to the Unacceptable Models List. This process may only be revised through the NERC Standards Development Process.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
    a. The model name;
    b. Alternative model name(s), if any;
    c. Organization(s) the submitting entity represents;
    d. Description of the model's stated intent;
    e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
    f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
    g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
    h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.
5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving

the change request, the NERC RSTC shall also recommend an effective date for the change.

6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

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

MOD-032-2 is posted for a 5-day final ballot.

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Term(s):

Distributed Energy Resource (DER): A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

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1. **Title:** Data for Power System Modeling and Analysis

2. **Number:** MOD-032-2

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Generator Owner

   4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   4.1.5 Resource Planner

   4.1.6 Transmission Owner

   4.1.7 Transmission Planner

   4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation:

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data, that is responsive to the technical concern.

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

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

   - Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. **Compliance Monitoring and Enforcement Program:** Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

3. **Potential Noncompliance (PNC) Abeyance Period:**
   For a period of two years following the phased-in compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2, Part 2.1 with respect to the provision of estimated aggregate DER data or estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. "Good faith" in this

context refers to a sincere intention to comply with Reliability Standard MOD-032-2 ~~regarding the provision of aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes in accordance with the data requirements and reporting procedures for the Planning Coordinator's planning area developed under Requirement R1, subject to the estimation requirements of~~ Requirement R2, Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. For example, the CEA may not pursue compliance enforcement actions during this period for entities who submit estimated data and include the supporting data explanation and methods used as detailed in Requirement R2 Part 2.1 in a timely manner. The CEA may pursue actions against entities who do not submit data with supporting explanation and methods in a timely manner. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.
R2.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not

	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider,	provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission

	Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission

	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data

	in the format specified by the ERO or its designee.	the format specified by the ERO or its designee.	required data in the format specified by the ERO or its designee.	in the format specified by the ERO or its designee.

D. Regional Variances

None.

E. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List
- ~~MOD-032 Supporting Document, Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO).~~

MOD-032-2 – ATTACHMENT 1
Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in Interconnection-wide cases. The joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify entity responsibility and data flow processes. The typical functional entity[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be identified by the bus number, name, and/or identifier that is assigned in conjunction with the Planning Coordinator, Transmission Owner, or Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
1. Each bus [TO] a. Nominal voltage b. Area, zone and owner 2. Aggregate Demand[3] [DP] a. Real and reactive power* b. In-service status* 3. Generating and storage units[4] [GO, TO[5], RP (for future planned resources only)] a. Real power capabilities - gross maximum and minimum values b. Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. Regulated bus* and voltage set point* (as typically provided by the TOP) e. Machine MVA base	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System Stabilizer [GO, RP (for future planned resources only)] 5. Aggregate Demand[3] [DP] 6. Wind plant model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control 8. Static Var Systems and FACTS [GO, TO, DP] 9. DC System Models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive sequence data b. Negative sequence data c. Zero sequence data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
f. Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. Generator type (hydro, wind, fossil, solar, nuclear, etc.) h. In-service status* 4. AC Transmission Line or Circuit [TO] a. Impedance parameters (positive sequence) b. Susceptance (line charging) c. Ratings (normal and emergency)* d. In-service status* 5. DC Transmission Systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. Nominal voltages of windings b. Impedance(s) c. Tap ratios (voltage or phase angle)* d. Minimum and maximum tap position limits e. Number of tap positions (for both the ULTC and NLTC) f. Regulated bus (for voltage regulating transformers)* g. Ratings (normal and emergency)* h. In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. Admittances (MVars) of each capacitor and reactor b. Regulated voltage band limits* (if mode of operation not fixed) c. Mode of operation (fixed, discrete, continuous, etc.) d. Regulated bus* (if mode of operation not fixed) e. In-service status* 8. Static Var Systems [TO] a. Reactive limits b. Voltage set point* c. Fixed/switched shunt, if applicable d. In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1)	a. parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. 11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]	

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics**	**short circuit**
b. Real power capability c. DER type (solar, battery, diesel generator, etc.) 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, DP, TO, TSP]		

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. (Note: This may be impacted by an aggregation threshold for DER specified under footnote 7.) A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This Supporting Document ~~attachment~~ describes the process by which changes may be made to the Unacceptable Models List. This process may only be revised through the NERC Standards Development Process.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
   a. The model name;
   b. Alternative model name(s), if any;
   c. Organization(s) the submitting entity represents;
   d. Description of the model's stated intent;
   e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
   f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
   g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
   h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.
5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back

to the ERO to work with the submitting entity. If the NERC RSTC recommends approving the change request, the NERC RSTC shall also recommend an effective date for the change.

6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

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

MOD-032-2 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

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):

Distributed Energy Resource (DER): A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

A. Introduction

1. **Title:** **Data for Power System Modeling and Analysis**

2. **Number:** **MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   ~~1.1.~~4.1. Functional Entities:

   ~~1.1.1~~4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   ~~1.1.2~~4.1.3 Generator Owner

   ~~**1.1.3** Load Serving Entity~~

   ~~1.1.4~~4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   ~~This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.~~

   ~~1.1.5~~4.1.5 Resource Planner

   ~~1.1.6~~4.1.6 Transmission Owner

   ~~1.1.7~~4.1.7 Transmission Planner

   ~~1.1.8~~4.1.8 Transmission Service Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

   ~~MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is~~

approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1, including the entity responsible for each required item.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

1.4. Specifications of the following items for dynamic model submissions:

1.4.1. Required submission of:

- standard library models incorporated within the software(s) utilized to create the Interconnection-wide case(s);
- user-defined models; or
- both standard library models and user-defined models.

1.4.2. Where user-defined models are accepted, usability requirements for any submitted user-defined models including, at a minimum, requirements to provide model documentation and instructions for model set up and use.

1.4.2.1. Each Planning Coordinator and Transmission Planner shall provide their user-defined model requirements within 90 calendar days of receiving a written request for such data from other Planning Coordinators and Transmission Planners within the Interconnection.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. If a functional entity is required to provide data for one or more of the following and is unable to gather such data, the functional entity shall provide an estimate of the data, an explanation of the limitations of the estimated data, and the method used for estimation;

- Aggregate DER data; or
- Data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.

2.2. If a functional entity is required to provide dynamic models, the functional entity shall provide the models accepted by the Transmission Planner under MOD-026, where such models are available.

2.3. If a functional entity provides a model that is included on the Unacceptable Models List maintained by the ERO in accordance with the process described in the MOD-032 Supporting Document, the functional entity shall also provide a technical rationale justifying the use of that model.

M2. Each ~~registered~~functional entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~2.1.~~3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data~~;~~, that is responsive to the technical concern.

~~3.1.~~3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each ~~registered~~functional entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

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

The applicable entity shall keep data or evidence to show compliance ~~with~~ 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.

- Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete 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.

2. Compliance Monitoring and ~~Assessment Processes~~ Enforcement Program:
Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for ~~a list of~~performing compliance monitoring and ~~assessment processes~~enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

~~**1.3. Additional Compliance Information**~~

~~None~~

3. Potential Noncompliance (PNC) Abeyance Period:
For a period of two years following the phased-in compliance date of Reliability Standard MOD-032-2 Requirement R2 under the associated implementation plan, the CEA will not pursue an action under Sections 4A.0 or 5.0 of Appendix 4C to the Rules of Procedure for a failure to comply with Reliability Standard MOD-032-2 Requirement R2, Part 2.1 with respect to the provision of estimated aggregate DER data or

estimated data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes against any entity acting in good faith to comply with the standard in accordance with the relevant implementation plan. “Good faith” in this context refers to a sincere intention to comply with Reliability Standard MOD-032-2 ~~regarding the provision of aggregate DER data or data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes in accordance with the data requirements and reporting procedures for the Planning Coordinator’s planning area developed under Requirement R1, subject to the estimation requirements of~~ Requirement R2, Part 2.1, following a reasonable and serious assessment by the entity in determining how this Reliability Standard should be applied to its particular facts and circumstances. For example, the CEA may not pursue compliance enforcement actions during this period for entities who submit estimated data and include the supporting data explanation and methods used as detailed in Requirement R2 Part 2.1 in a timely manner. The CEA may pursue actions against entities who do not submit data with supporting explanation and methods in a timely manner. Entities shall participate in any compliance monitoring activities undertaken by the CEA during this potential noncompliance abeyance period and submit documentation as requested.

~~Table of Compliance Elements~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) ~~Coordinator~~ did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

R2.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;

	the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	greater than 25%, but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	greater than 50%, but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, ~~Load Serving Entity,~~ Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its

				Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.
R3.	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response	The Balancing Authority, Distribution Provider, Generator Owner~~, Load Serving Entity~~, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement ~~R4~~R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

	within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	
R4.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 25%, but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 50%, but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee, but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

- ~~None.~~Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale
- ERO Unacceptable Models List

MOD-032-2 – ATTACHMENT 1~~:~~

Data Reporting Requirements

The table below indicates the information[1] that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in ~~*the*~~ Interconnection-wide cases. ~~*A*~~The joint Planning Coordinator ~~*may*~~/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1 will specify ~~*additional information that includes specific information required for each item in the table below. Each*~~entity responsibility and data flow processes. The typical functional *entity*~~[1]~~[2] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be ~~*as*~~ identified by the bus number, name, and/or identifier that is assigned in conjunction with the ~~*PC, TO*~~Planning Coordinator, Transmission Owner, or ~~*TP.*~~ Transmission Planner.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	**short circuit**
1. Each bus [TO] a. ~~n~~Nominal voltage b. ~~a~~Area, zone and owner 2. Aggregate Demand~~[3]~~[2] [~~LSE~~DP] a. ~~r~~Real and reactive power* b. ~~i~~In-service status*	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP (for future planned resources only)] 3. Governor [GO, RP (for future planned resources only)] 4. Power System ~~S~~stabilizer [GO, RP(for future planned resources only)]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO, DP] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO]

~~[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).~~

~~[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
3. Generating and storage Units[4] ~~3~~ [GO, TO[5], RP (for future planned resources only)] a. ~~r~~Real power capabilities - gross maximum and minimum values b. ~~r~~Reactive power capabilities - maximum and minimum values at real power capabilities in 3a above c. ~~s~~Station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. ~~r~~Regulated bus* and voltage set point* (as typically provided by the TOP) e. ~~m~~Machine MVA base f. ~~g~~Generator step up transformer data (provide same data as that required for transformer under item 6, below) g. ~~g~~Generator type (hydro, wind, fossil, solar, nuclear, etc) h. ~~i~~In-service status* 4. AC Transmission Line or Circuit [TO] a. ~~i~~Impedance parameters (positive sequence) b. ~~s~~Susceptance (line charging) c. ~~r~~Ratings (normal and emergency)* d. ~~i~~In-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. ~~n~~Nominal voltages of windings	5. Aggregated Demand[3] [~~LSE~~DP] 6. Wind ~~T~~turbine ~~Data~~model (for plants with type 1 and type 2 wind turbines) [GO] 7. Inverter-Based Resource [GO, TO[5]]~~Photovoltaic systems [GO]~~ ~~7.~~a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control. 8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP] 9. DC ~~s~~System models [TO] 10. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control or information that can be used to infer those items for modeling purposes. b. Indication whether DERs are subject to tripping in conjunction with UFLS or UVLS. ~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]	3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]

~~[3] Including synchronous condensers and pumped storage.~~

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
b. ~~i~~Impedance(s) c. ~~t~~Tap ratios (voltage or phase angle)* d. ~~m~~Minimum and maximum tap position limits e. ~~n~~Number of tap positions (for both the ULTC and NLTC) f. ~~r~~Regulated bus (for voltage regulating transformers)* g. ~~r~~Ratings (normal and emergency)* h. ~~i~~In-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. ~~a~~Admittances (MVars) of each capacitor and reactor b. ~~r~~Regulated voltage band limits* (if mode of operation not fixed) c. ~~m~~Mode of operation (fixed, discrete, continuous, etc.) d. ~~r~~Regulated bus* (if mode of operation not fixed) e. ~~i~~In-service status* 8. Static Var Systems [TO] a. ~~r~~Reactive limits b. ~~v~~Voltage set point* c. ~~f~~Fixed/switched shunt, if applicable d. ~~i~~In-service status* 9. Aggregate Distributed Energy Resource (DER) data[7] [DP, TO][6] a. Location (bus from item 1) b. Real power capability c. DER type (solar, battery, diesel generator, etc.)		

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	dynamics ~~*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*~~	short circuit
~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP]		

~~Guidelines and Technical Basis~~

~~For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.~~

~~The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.~~

~~An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.~~

~~The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and~~

~~to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).~~

~~The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).~~

~~Rationale:~~

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

~~Rationale for R1:~~

~~This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short-circuit data also required to perform short-circuit studies. The addition of short-circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.~~

~~In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.~~

~~This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.~~

~~This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:~~

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:
    a. add requirement identifying who provides and who receives data;
    b. identify acceptability;
    c. standard format;
    d. how to deal with new technologies (user written models if no standard model exists); and
    e. shareability.
4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

~~This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.~~

~~Rationale for R4:~~

~~This requirement will replace MOD-014 and MOD-015.~~

~~This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.~~

~~The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).~~

~~This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).~~

~~For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.~~

Attachment 1 Data Reporting Requirements Footnotes

1. Data specified in the sub-bullets of each column that are required for both steady-state and dynamics are not duplicated in the table.
2. For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).
3. For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 under Steady State Column that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. (Note: This may be impacted by an aggregation threshold for DER specified under footnote 7.) A Distribution Provider is the typical responsible entity for providing this information, generally through coordination with the Transmission Owner.
4. Generating and storage units include IBRs, and synchronous condensers.
5. The Transmission Owner is the typical entity responsible for collecting and providing data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes.
6. The Distribution Provider is the typical responsible entity for collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system.
7. Aggregation thresholds for DERs may be specified in the joint Planning Coordinator/Transmission Planner modeling data requirements and reporting procedures developed under Requirement R1.

MOD-032 Supporting Document

Process for Updating the Unacceptable Models List Maintained by the Electric Reliability Organization (ERO)

The Unacceptable Models List is maintained separately by NERC as the ERO. This Supporting Document describes the process by which changes may be made to the Unacceptable Models List. This process may only be revised through the NERC Standards Development Process.

The following steps shall be taken to add a model to or remove a model from the Unacceptable Models List:

1. Any person or entity may submit a request to the ERO to add or remove a model from the Unacceptable Models List. This request shall include, at a minimum:
   a. The model name;
   b. Alternative model name(s), if any;
   c. Organization(s) the submitting entity represents;
   d. Description of the model's stated intent;
   e. Request to add model as an "unacceptable" model or remove "unacceptable" model designation;
   f. Technical supporting documentation describing the ability or inability of the model to appropriately represent small and large disturbance behavior;
   g. Identification of any Confidential Information as defined in Section 1500 of the NERC Rules of Procedure; and
   h. An explanation, if any of the above technical support items are unavailable to the submitting entity.
2. ERO staff shall review and evaluate the information in the Unacceptable Models List change request, along with any group or subcommittee of the NERC Reliability and Security Technical Committee, or its successor (RSTC), charged with assisting in such reviews. If no such group or subcommittee has been identified, ERO staff may work with other industry subject matter experts as needed to review and evaluate the request.
3. ERO staff shall provide public notice that identifies the model being considered for addition to or removal from the list, includes a non-confidential summary of the rationale offered, and provides at least 30 days to submit comments.
4. The results of the ERO review and the recommended action shall be presented to the NERC RSTC in a duly noticed public meeting.

5. The NERC RSTC may recommend the NERC Vice President of Engineering and Standards approve the change request, reject the change request, or remand the application back to the ERO to work with the submitting entity. If the NERC RSTC recommends approving the change request, the NERC RSTC shall also recommend an effective date for the change.
6. The NERC Vice President of Engineering and Standards, considering the recommendation of the NERC RSTC, shall approve the change request, reject the change request, or remand the application back to ERO staff to work with the submitting entity. If approved, the NERC Vice President of Engineering and Standards shall also determine the effective date for the change.
7. The ERO shall provide public notice of a change to the Unacceptable Models List along with the effective date of the change. The revised Unacceptable Models List shall be posted to the NERC website and filed with the applicable governmental authorities for informational purposes.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving MOD-032-1.	See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements.
2	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2022-02.

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

IRO-010-6 is posted for a 5-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
25-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection
2. **Number:** IRO-010-6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Transmission Operator
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments, as deemed necessary by the Reliability Coordinator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2 and Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R1	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	
6	TBD	Adopted by NERC Board of Trustees	FERC Order 901 Modifications

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

IRO-010-6 is posted for a 5-day ballot period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
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25-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

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2. **Number:** IRO-010-6
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
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   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Transmission Operator
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments, as deemed necessary by the Reliability Coordinator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification ~~as deemed necessary by the Reliability Coordinator~~.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

1.5.4 Provisions to update or correct data and information, as applicable or necessary;

1.5.5 A mutually agreeable format; and

1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2 and Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R1	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications, but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Project 2022-02 Implementation Plan
- Project 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO-010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	
6	TBD	Adopted by NERC Board of Trustees	FERC Order 901 Modifications

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

IRO-010-6 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection

2. **Number:** IRO-010-~~5~~6

3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.

4. **Applicability:**

   4.1. Reliability Coordinator

   4.2. Balancing Authority

   4.3. Generator Owner

   4.4. Generator Operator

   4.5. Transmission Operator

   4.6. Transmission Owner

   4.7. Distribution Provider

5. **Effective Date:** See Implementation Plan for Project ~~2021-06.~~2022-02.

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments, as deemed necessary by the Reliability Coordinator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification ~~as deemed necessary by the Reliability Coordinator~~.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints.

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to ~~.~~:

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

~~**1.5.3**~~**1.5.4** Provisions to update or correct data and information, as applicable or necessary ~~.~~;

~~1.5.4~~1.5.5 A mutually agreeable format~~.~~; and

~~1.5.5~~1.5.6 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include, but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or ~~e-mail~~email records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, ~~Reliability Coordinator,~~ Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include, but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

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 the ~~mandatory and enforceable~~NERC 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~~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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.
- The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2~~,~~ and Measure M2.
- Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

1.3. Compliance Monitoring and Enforcement Program:
~~As defined in the NERC Rules of Procedure,~~ "Compliance Monitoring and Enforcement Program" ~~refers~~or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the ~~identification~~NERC Rules of Procedure) or the Commission-approved program of ~~the processes~~a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that ~~will be used to evaluate data or~~

~~information~~is responsible for ~~the purpose of assessing performance or outcomes~~performing compliance monitoring and enforcement activities with ~~the associated reliability standard~~respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R1.	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the ~~SDT~~DT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				

R#	Violation Severity Levels			
	Lower	Moderate	High	Severe
R2.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet one of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet two of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specification.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

- Project 2022-02 Implementation Plan
- Project 2022-002 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO- 010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06
5	November 2, 2023	FERC approved IRO-010-5. Docket No. RD23-6-000	

6	TBD	Adopted by NERC Board of Trustees	FERC Order 901 Modifications

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

TOP-003-8 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, as deemed necessary by the Transmission Operator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, but is not limited to:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

1.5.4. Provisions to update or correct data and information, as applicable or

necessary;

1.5.5. A mutually agreeable format;

1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, as deemed necessary by the Balancing Authority, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes, but is not limited to:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

2.5.4. Provisions to update or correct data and information, as applicable or necessary.

2.5.5. A mutually agreeable format.

2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator

Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (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 Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1, Part1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, Board Of Trustees approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5. Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1. Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7. Docket	

		No.RD25-5-000	
8	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives

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

TOP-003-8 is posted for a 5-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 19, 2022
SAR posted for comment	February 1 – March 2, 2022
45-day formal comment period with ballot	May 31, 2023 – July 14, 2023
45-day formal comment period with additional ballot	October 6 – November 20, 2023
45-day formal comment period with additional ballot	August 27 – October 10, 2024
30-day formal comment period with initial ballot	April 17 – May 16, 2025
34-day formal comment period with ballot	August 8 –September 10, 2025

Anticipated Actions	Date
5-day final ballot	September 29 – October 3, 2025
Board adoption	October 14, 2025

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection
2. **Number:** TOP-003-8
3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.
4. **Applicability:**
   - **4.1** Functional Entities:
     - **4.1.1** Transmission Operator
     - **4.1.2** Balancing Authority
     - **4.1.3** Generator Owner
     - **4.1.4** Generator Operator
     - **4.1.5** Transmission Owner
     - **4.1.6** Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, as deemed necessary by the Transmission Operator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification ~~as deemed necessary by the Transmission Operator~~.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, ~~at a minimum,~~ but is not limited to~~the following~~:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

1.5.4. Provisions to update or correct data and information, as applicable or necessary;

1.5.5. A mutually agreeable format;

1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, as deemed necessary by the Balancing Authority, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information~~, as deemed necessary by the Balancing Authority~~, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts;

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes~~, at a minimum the following~~but is not limited to:

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

2.5.4. Provisions to update or correct data and information, as applicable or necessary.

2.5.5. A mutually agreeable format.

2.5.6. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations*

Planning, Same-Day Operations, Real-time Operations]

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (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 Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of

the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the drafting team is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1, Part1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1, Part 1.5 or Requirement R2, Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, Board Of Trustees approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
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5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5. Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
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6.1	November 3, 2023	Effective Date	July 1, 2025
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7	February 26, 2025	FERC approved TOP-003-7. Docket	

		No.RD25-5-000	
8	TBD	Adopted by the NERC Board of Trustees	Revisions to address FERC Order No. 901 directives

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A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-~~7~~8

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-~~03~~02.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, as deemed necessary by the Transmission Operator, including non-BES data and information, external network data and information, Inverter-based Resource (IBR)-specific data and parameters, and identification of the entities responsible for responding to the specification ~~as deemed necessary by the Transmission Operator~~.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following~~.~~:

1.5.1. Specified deadlines or periodicity in which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operations purposes, as applicable;

~~1.5.3.~~**1.5.4.** Provisions to update or correct data and information, as applicable

or necessary;

~~1.5.4.~~1.5.5. A mutually agreeable format;

~~1.5.5.~~1.5.6. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, as deemed necessary by the Balancing Authority, including non-Bulk Electric System data and information, IBR-specific data and parameters, and external network data and information, ~~as deemed necessary by the Balancing Authority,~~ and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

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~~**2.5.3.**~~**2.5.4.** Provisions to update or correct data and information, as applicable or necessary.

~~**2.5.4.**~~**2.5.5.** A mutually agreeable format.

~~**2.5.5.**~~**2.5.6.** A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or ~~e-mail~~email records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or ~~e-mail~~email records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in

Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "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 Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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

- Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence

for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program (Appendix 4C to the NERC Rules of Procedure) or the Commission-approved program of a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible for performing compliance monitoring and enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions,

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Real-time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 VSLs only, the intent of the ~~Standard~~ Drafting Team (~~SDT~~DT) is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	Assessments.	
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification, but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

- 2022-02 Implementation Plan
- 2022-02 Technical Rationale

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No. RD23-6-000	
6.1	November 3, 2023	Effective Date	July 1, 2025
7	December 10, 2024	Board Adopted	Revisions under Project 2022-03
7	February 26, 2025	FERC approved TOP-003-7 Docket No.RD25-5-000	

~~7~~8	TBD	~~Energy Assurance Modifications — Addition of Near-Term ERA.~~Adopted by the NERC Board of Trustees	~~Revised~~Revisions to address FERC Order No. 901 directives

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Implementation Plan

Project 2022-02 Uniform Modeling Framework for IBR

Applicable Standard(s)

- Reliability Standard MOD-032-2 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-6 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-8 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement(s)

- Reliability Standard MOD-032-1 Data for Power System Modeling and Analysis
- Reliability Standard IRO-010-5 Reliability Coordinator Data and information Specification and Collection
- Reliability Standard TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard(s)

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

- None

Applicable Entities

- See subject standards

Glossary of Terms used in NERC Reliability Standards

This section includes a newly defined term used in the NERC Reliability Standards. The new definition listed below becomes approved when the proposed standard is approved. When the standard becomes effective, the defined term will be removed from the individual standard and added to the NERC Glossary.

Proposed New Definition:

Distributed Energy Resource (DER):

A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system.

Background

As the penetration of DERs continues to increase across the many distribution systems connected both directly and indirectly to the North American Bulk-Power System (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BPS. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DERs for planning studies (including both utility-scale and retail-scale DERs) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs), including updated modeling data requirements specific to DERs.

Further, in Order No. 901,[1] the U.S. Federal Energy Regulatory Commission ("FERC") found that it is imperative for NERC to develop new or modified Reliability Standards to address reliability concerns "related to IBRs at all stages of interconnection, planning, and operations."[2]. Among other things, FERC directed NERC to develop requirements addressing the provision of IBR and DER data to the entities responsible for the planning and operation of the BPS. Detailed information on the specific FERC Order No. 901 directives addressed through this project is available in Project 2022-02 Consideration of Order No. 901 Directives.

Proposed Reliability Standard MOD-032-2 replaces Load-Serving Entity with Distribution Provider as an applicable entity. Data items specific to IBRs and DERs were added to Attachment 1: Data Reporting Requirements, consistent with addressing the FERC Order No. 901 directives. Proposed Reliability Standard MOD-032-2 also adds a new Part 1.4 in Requirement R1, which would require the Planning Coordinator and Transmission Planner to specify submission of standard library dynamic models, user-defined models or both. Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. New Requirement R1, Part 1.4.2 is responsive to FERC concerns about model usability and non-convergence by requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions. New Requirement R2, Part 2.1 addresses estimation of unregistered IBR or DER data where actual data is not available, consistent with the directives in Order No. 901. New Requirement R2, Part 2.2 addresses the provision of dynamic models accepted under the MOD-026 standard, and new Requirement R2, Part 2.3 requires any entity submitting a model included on the Unacceptable Model List maintained by the ERO to include a technical rationale with its submission supporting the use of the model. Altogether, these modifications establish a uniform modeling framework that incorporates both IBR and DER data and facilitates model accuracy in alignment with FERC Order No. 901.

[1] Reliability Standards to Address Inverter-Based Resources, Order No. 901, 185 FERC ¶ 61,042 (2023).
[2] Id. at P 25

Revisions in the Reliability Standards TOP-003-8 and IRO-010-6 data specification standards specify that entities responsible for developing and distributing data specifications shall include requirements for model submissions consistent with the model submitted for planning purposes, as applicable.

General Considerations

In developing this implementation plan, the drafting team (DT) considered the time that would be necessary to update modeling data requirements and reporting procedures for MOD-032-2, including identifying the proper reporting entity for modeling data related to IBRs (including IBRs that are not DERs and do not meet the criteria that would require the owner(s) to register with NERC for mandatory Reliability Standards compliance purposes) and aggregate DERs. The DT also considered that the standard would become applicable to the Distribution Provider (DP) for the first time. During the 24 months prior to the effective date of Requirement R1, the applicable entities would be expected to participate in PC/TP processes to change the modeling data reporting requirements related to IBRs and aggregate DERs and should be able to start working on data collection processes and methods. The applicable entities in Requirement R2 would then have an additional 12 months to complete and implement data collection prior to the compliance dates of Requirements R2, R3, and R4. This timeline also allows for the development of new data estimation processes developed under MOD-032-2 Requirement R2, Part 2.1 and for the development of technical rationale to support the use of models included on the Unacceptable Model List maintained by the ERO, where applicable. Requirements adjusted in Reliability Standards IRO-010-6 and TOP-003-8 may not be practical to implement prior to full implementation of MOD-032-2, and therefore were set to the same implementation timeline. One additional limitation the DT considered is the requirement for all FERC Order No. 901 directives to be fully implemented by January 1, 2030, including those to be addressed by future standard revisions that may be dependent upon the implementation of these standard revisions.

In summary, this implementation plan would provide a full 36 months for MOD-032 Requirements R2, R3, R4, IRO-010, and TOP-003 from FERC approval until data is required to be reported under the revised requirements. During the phased-in compliance period for Requirements R2-R4, entities shall continue to provide data and perform other required actions in accordance with specifications developed under Reliability Standard MOD-032-1, unless entities are able to comply with the revised requirements sooner.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard and NERC Glossary term Distributed Energy Resource is provided below. Where the DT 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 MOD-032-2

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

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

Compliance Date for Reliability Standard MOD-032-2 Requirements R2, R3, and R4

Entities shall not be required to comply with Requirements R2, R3, and R4 relating to revised Planning Coordinator and Transmission Planner data requirements and reporting procedures developed under MOD-032-2 Requirement R1 and Attachment 1 until 12 months after the effective date of Reliability Standard MOD-032-2.

During the phased-in compliance period, entities shall continue to comply with Requirements R2, R3, and R4 related to Planning Coordinator/Transmission Planner data requirements and reporting procedures developed under MOD-032-1 Requirement R1 and Attachment 1 unless they are compliant with revised Planning Coordinator/Transmission Planner data requirements and reporting procedures under Reliability Standard MOD-032-2 Requirement R1.

Definition – Distributed Energy Resource (DER)

Where approval by an applicable governmental authority is required, the definition of Distributed Energy Resource (DER) shall become effective on the first day of the first calendar quarter that is after the effective date of the applicable governmental authority's order approving Reliability Standard MOD-032-2, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is after the date that Reliability Standard MOD-032-2 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard IRO-010-6

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Reliability Standard TOP-003-8

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is thirty-six (36) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard MOD-032-1

Reliability Standard MOD-032-1 shall be retired immediately prior to the effective date of Reliability Standard MOD-032-2 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard IRO-010-5

Reliability Standard IRO-010-5 shall be retired immediately prior to the effective date of Reliability Standard IRO-010-6 in the particular jurisdiction in which the revised standard is becoming effective.

Reliability Standard TOP-003-7

Reliability Standard TOP-003-7 shall be retired immediately prior to the effective date of Reliability Standard TOP-003-8 in the particular jurisdiction in which the revised standard is becoming effective.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2022-02 Uniform Modeling Framework for IBR

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-02 Uniform Modeling Framework for Inverter-Based Resources (IBRs). 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 the Federal Energy Regulatory Commission (FERC)-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The drafting team applied the following North American Electric Reliability Corporation (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.

MOD-032-2

VRF Justification for MOD-032-2, Requirement R1

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R1 require model submission in accordance with the Criteria for Acceptable Models maintained by the ERO. This is similar to other sub-requirements in Requirements R1; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R1

Please refer to the VSL table below.

VRF Justification for MOD-032-2, Requirement R2

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. “Load Serving Entity” was replaced with “Distribution Provider” from Requirement R2 in MOD-032-2. In addition, Requirement R2 added a sub-requirement requiring if entity is unable to gather unregistered IBR data or Distributed Energy Resource (DER) data to complete an estimate. These modifications align with the medium risk requirement and therefore, the VRF remained medium.

VSL Justification for MOD-032-2, Requirement R2

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R3

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard. The modifications made to Requirement R3 were administrative in nature; therefore, the VRF remained a low.

VSL Justification for MOD-032-2, Requirement R3

Please refer to the VSL table located below**.**

VRF Justification for MOD-032-2, Requirement R4

The VRF did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSL Justification for MOD-032-2, Requirement R4

The VSL did not change from the previously FERC approved MOD-032-1 Reliability Standard.

VSLs for MOD-032-1, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25%, but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50%, but less than or equal to 75% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified in Requirement R1.

VSL Justifications for MOD-032-1, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional sub-requirement to Requirement R1. The proposed VSL was modified to reflect the additional sub-requirement. It does not have an 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 updated sub-requirement requires the responsible entity to follow the Criteria for Acceptable Models document maintained by the Electric Reliability Organization. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25%, but less than or equal to 50% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25%, but less than or equal to 50% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50%, but less than or equal to 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50%, but less than or equal to 75% of the required data failed to meet data format,	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s); OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner,

of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in less than or equal to 15 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 15, but less than or equal to 30 calendar days after the specified date.	shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 30, but less than or equal to 45 calendar days after the specified date.	Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications; OR The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures, but did provide the data in greater than 45 calendar days after the specified date.

VSL Justifications for MOD-032-1, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	"Load Serving Entity" was replaced with "Distribution Provider" from Requirement R2 and a sub-requirement was added requiring if entity is unable to gather unregistered IBR data or DER data to complete an estimate. The proposed VSL was modified to reflect the additional sub-requirement language. It does not have an 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 updated sub-requirement requires the entity if it is unable to gather unregistered IBR data or DER data to complete an estimate. The VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for MOD-032-1, Requirement 3			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days, but less than or equal to 120 calendar days (or within greater than 15 calendar days, but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days, but less than or equal to 135 calendar days (or within greater than 30 calendar days, but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).	The Balancing Authority, Distribution Provider, Generator Owner, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R3 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).

VSL Justifications for MOD-032-1, Requirement 3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by replacing Load Serving Entity with Distribution provider. The proposed VSL was modified to reflect this modification. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

IRO-010-5

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for IRO-010-5, Requirement R1

Please refer to the VSL table located below.

VRF Justification for IRO-010-5, Requirement R1

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R2

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VRF Justification for IRO-010-5, Requirement R3

The VRF did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSL Justification for IRO-010-5, Requirement R3

The VSL did not change from the previously FERC approved IRO-010-4 Reliability Standard.

VSLs for IRO-010-5, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

VSL Justifications for IRO-010-5, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSLs are not binary and do not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

TOP-003-8

VRF Justification for TOP-003-8, Requirement R1

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R1

Please refer to the VSL table located below.

VRF Justification for TOP-003-8, Requirement R2

The VRF did not change from the previously FERC approved TOP-003-8 Reliability Standard. The modifications made to Requirement R1 require IBR-specific data and parameters to be added to the list of data and information needed by the Reliability Coordinator per Part 1.1. and model submission in accordance with the Criteria for Acceptable Models maintained by the Electric Reliability Organization per Part 1.5.3. This is similar to other sub-requirements in R1; therefore, the VRF remained a low.

VSL Justification for TOP-003-8, Requirement R2

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R3

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R3

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R4

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R4

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VRF Justification for TOP-003-8, Requirement R5

The VRF did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSL Justification for TOP-003-8, Requirement R5

The VSL did not change from the previously FERC approved TOP-003-7 Reliability Standard.

VSLs for TOP-003-8, Requirement 1			
Lower	**Moderate**	**High**	**Severe**
The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

VSL Justifications for TOP-003-8, Requirement 1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R1. The purposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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.

VSLs for TOP-003-8, Requirement 2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-8, Requirement 2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding additional sub-requirements to Requirement R2. The proposed VSL was modified to reflect the additional sub requirement. It does not have an 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 VSL uses the same terminology as used in the associated requirement; therefore, it is consistent with the requirement.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement; therefore, it is 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

NERC Project 2022-02 | MOD-032-2, TOP-003-8, and IRO-010-6
September 2025

MOD-032-2 – Data for Power System Modeling and Analysis

Rationale for Applicability Section

For MOD-032-2, Load-Serving Entity (LSE) was replaced with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria. It should be noted that Generator Owner (GO) applicability includes both Category 1 GO and Category 2 GO consistent with proposed revisions to the definitions of those terms developed under Project 2024-01 Rules of Procedure Definitions Alignment.

Additionally, the drafting team (DT) reviewed the dual applicability to Planning Authority (PA) and Planning Coordinator and determined that it was most appropriate to reference both terms in the applicability section until NERC registration criteria are updated to use only a single term. The posted "Appendix 5B: Statement of Compliance Registry Criteria," dated June 27, 2024, still uses both terms and, arguably, the PA term is used more prominently. However, the explanation included in MOD-032-1 refers to synchronization between registration criteria and the NERC functional model which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the DT excluded the explanatory language from MOD-032-2 Applicability Section.

Rationale for Distributed Energy Resource (DER) Definition

The DT has proposed that a definition for DER be added to the *NERC Glossary of Terms used in Reliability Standards* (NERC Glossary of Terms). The approved standard authorization request (SAR) to revise MOD-032, submitted December 2021, noted that "it may be needed (based on the discretion of the DT) to add a definition for 'Distributed Energy Resource (DER)' to the NERC Glossary of Terms" in conjunction with adding DER data to Attachment 1, the main purpose of this SAR.[1] The DT found it necessary to draft a DER definition to clarify the usage of this term within the standard. Further, the DT recognized benefits of a NERC Glossary of Terms definition to bring alignment and consistency of term usage across Reliability Standards. Additionally, the term Inverter-Based Resource (IBR) was recently defined in the NERC Glossary of Terms under Project 2020-06 for a similar reason. Finally, the DT was comprised of team members with adequate experience to propose a definition, including members of the NERC SPIDERWG and IEEE 1547 working group.

The DT proposes to define Distributed Energy Resource (DER) as follows:

"A generator or energy storage technology connected to a distribution system that is capable of providing Real Power in non-isolated parallel operation with the Bulk-Power System, including one connected behind the meter of an end-use customer that is supplied from a distribution system."

[1] SAR title "MOD-032-1 Data for Power System Modeling and Analysis", submitted 12/15/2021. Available at: https://www.nerc.com/pa/Stand/Project202202ModificationstoTPL00151andMOD0321DL/2022-02_MOD-032%20SAR%20SPIDERWG_020122.pdf

In developing this definition, the DT considered various DER definitions utilized in the industry and discussed in the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Terms and Definitions Working Document, including the six other definitions described in Appendix D that were not adopted by SPIDERWG. Through this review, the DT determined each of these seven definitions would benefit from refinement to be most suitable for application in MOD-032 and future reliability standards more broadly. It is expected that most reliability standard revision proposals related to DERs would originate from the SPIDERWG. Thus, the DT's intent was to propose a DER definition that aligned with the SPIDERWG working definition, which explicitly excludes demand response and clarifies what is in scope and out of scope with respect to where a DER is connected, rather than the technology type. The DT's concurrence in excluding demand response from the definition of DER is due to demand response characteristics that are typically reflected in base case study assumptions rather than requiring explicit modeling within reliability simulations.

The DT considered adopting a voltage threshold to define distribution. However, industry generally differentiates transmission from distribution based on the functional use of the system rather than technical specifications (e.g., voltage, active power, etc.). Setting aside the Bulk Electric System, that has a NERC definition, defining electric facilities as either transmission or distribution is often based on State law or regulations, ISO/RTO tariff, and/or utility tariffs. There are no conflicts in how applicable entities define distribution and transmission facilities for a given region, even if those definitions vary from region to region. Additionally, the DT considered an active power threshold to define DER and concluded that DER technologies can vary in size, and a threshold might inappropriately exclude technologies that are DER[2]. At the same time, the DT understands that certain applications of DER data, for instance determining when or how a Transmission Planning (TP) or Planning Coordinator (PC) includes DERs into planning processes (e.g., TPL-001), may include active power or other TP or PC defined thresholds.

The DT considered defining DER based on the resource not being connected to the Bulk Power System (BPS), similar to the IEEE 1547-2018 definition that uses "not directly connected to the BPS" to describe DERs. However, the NERC Glossary of Terms definition of BPS does not provide specificity that would enhance a definition of DER beyond an undefined term that is generally used in industry. The phrase "distribution system" was selected to expressly describe the type of electric facilities that would cause a resource to be defined as a DER, if interconnected to those facilities.

The DT recognizes that "distribution system" is not defined in the NERC Glossary of Terms and that the SPIDERWG proposed a definition.[3] The DT reviewed the SPIDERWG definition and concluded that it would not clarify the term DER. The SPIDERWG use of the term "transmission-distribution" interface within a definition of "distribution system" could be considered a circular reference that causes ambiguity. The DT is not proposing a definition for distribution system given any proposed definition could be of limited benefit for clarifying the proposed definition for DER.

[2] NERC has published a study recommending that a zero MVA threshold be used when collecting DER information: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

[3] SPIDERWG definition of "distribution system": The electrical facilities that are located behind a transmission-distribution transformer that serves multiple end-use customers.
https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

Below is a summary of the rationale for the DT departing from each of the seven definitions when proposing a new DER definition.

SPIDERWG definition
After considering the SPIDERWG definition, the DT determined it provided a useful foundation but needed refinement to be suitable for the intended use. Specifically, the SPIDERWG term included transient types of DER power beyond generation and storage, and it included sources of back-up power that would have no potential grid impacts.

The DT chose to refer to a generator or storage technology specifically, rather than use the SPIDERWG language of "source", to exclude devices or resources that only transiently inject real power (e.g., regenerative elevators, transition switches, etc.). A DER can use various technologies including synchronous machines, induction machines, and power inverters/converters (i.e., IBR). Different types of DERs can utilize a wide range of energy sources including, but not limited to, natural gas, diesel, hydro, storage, wind, and solar. Additionally, the DT intention was to ensure that the scope included facilities "connected behind the meter of an end use customer" that may export Real Power to the power system or offset Real Power load (e.g., residential solar or commercial rooftop solar). This would exclude technologies such as charging-only electric vehicle (EV) installations and controllable load. While not finalized, it is the drafting team's understanding that this determination is consistent with recent proceeding from the IEEE 1547 revision Working Group. To exclude transmission connected load customers that have onsite generation or storage resources, the DER definition clarifies that the behind-the-meter customer "is supplied from a distribution system".

The DT included the language "in non-isolated parallel operation with the Bulk-Power System" to indicate that a distributed energy resource with potential BPS reliability impacts is only one that has electrical connectivity to the BPS. A resource that is only operated in islanded or isolated mode (e.g., back-up generation that only operates when a facility is disconnected from the grid), will not have an impact to the BPS and, therefore, is not of interest from a BPS-reliability perspective. The DT understands the concepts of non-isolated parallel operation versus isolated parallel operation to be commonly understood within the industry. The DT intentionally avoided the term "directly connected" to differentiate electrical connectivity from an electrical connection point. The phrase "connected to the distribution system" speaks to electrical connectivity and the subsequent phrase "including one connected behind the meter of an end use customer" clarifies this connectivity includes a resource directly connected to a customer system (i.e., behind the meter).

IEEE 1547-2018
The DT reviewed the IEEE 1547-2018 definition and found that it contained elements that could supplement the SPIDERWG definition to address the issues identified above. The DT incorporated the explicit reference to generation and storage aspect of the IEEE definition. Further, the IEEE concept of "capable of exporting active power to an EPS" informed the need for capturing non-isolated, long-term paralleling and the sourcing of Real Power (i.e., active power) within the DT definition.

At the same time, the DT did not view the IEEE definition as suitable for the DT's intended use as written. The IEEE term qualifies the DER connection point as "not directly connected to a bulk power system" which the DT viewed as potentially ambiguous. Instead, the DT opted for the "connected to a distribution system" language to point to the electric system location, and how facilities at that location are classified, as a key concept in differentiating DERs from other generators and energy storage technology. The DT considered if it was necessary to define "supplemental DER devices" as part of the DER definition and determined this nuance is not needed for a NERC Glossary of Terms DER definition.

Federal Energy Regulatory Commission (FERC) Energy Primer
The DT identified the FERC Energy Primer definition as being inclusive of load resources (e.g., energy efficiency, demand response) which is not aligned with the SPIDERWG definition. Given the reliability use cases, the DT and SPIDERWG definitions target sources of electric power, with the DT narrowing this definition to be only sources "capable of providing Real Rower." After considering the FERC definition, the DT determined it was not suitable for the intended use.

National Association of Regulatory Utility Commissions (NARUC)
NARUC's definition is also inclusive of load resources (e.g., energy efficiency, demand response) and therefore, the DT concluded it is too broad.

NERC DERTF
The NERC DERTF definition uses the language "resource on the distribution system that produces electricity" which appears to exclude distributed energy storage, a technology necessary for inclusion in the DT definition. Further, the NERC DERTF definition defines DER as anything "not otherwise included in the formal NERC definition of the Bulk Electric System" which the DT views as overly broad.

California Public Utilities Commission (CPUC)
The CPUC definition appears to be based on California legislation and includes energy efficiency, EVs, demand response, renewable generation resources, and energy storage. As is the case for FERC and NARUC definitions above, the inclusion of load resources is overly broad for the NERC Glossary of Terms.

New York Independent System Operator (NYISO)
The NYISO definition only considers market-qualifying resources as DER. This definition's exclusion of a large portion of DER (i.e., retail participation) is too narrow for the reliability planning needs identified by the SPIDERWG DER Modeling Study.

Figure 1 below provides a graphic illustration of the DER definition and the intended scope of facilities that would fall under the proposed definition. Figure 2 below shows that the proposed DER and IBR definitions are compatible, but distinct. Some resources may be classified as a DER, but not an IBR; some resources may be classified as an IBR, but not a DER; some resources may be classified as both a DER and an IBR. Rather than separately define IBR-DER, the DT suggests IBR-DER should be used to reference those devices meeting both the definition of IBR and the definition of DER, as demonstrated by the overlapping area of Figure 2. This relationship between the definitions and the existence of non-IBR storage solutions informed the phrasing of "generator and energy storage technology" to ensure all generators and all storage devices

are included, even if they do not meet the definition of IBR. Note that in Figure 2, "distribution-connected" is shorthand for connected to the distribution system and "bulk system-connected" refers to resources connected to the transmission system.

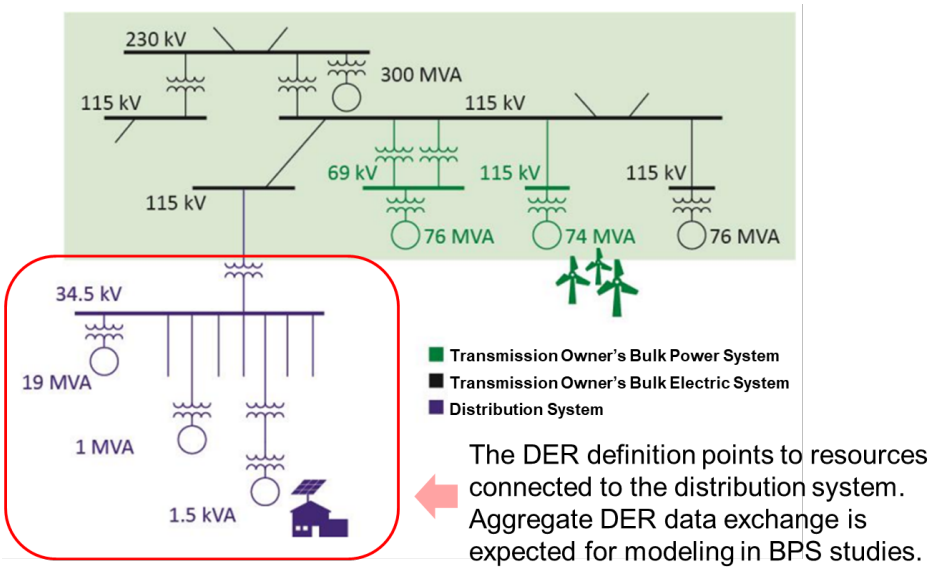


Figure 1: DER Definition Illustration

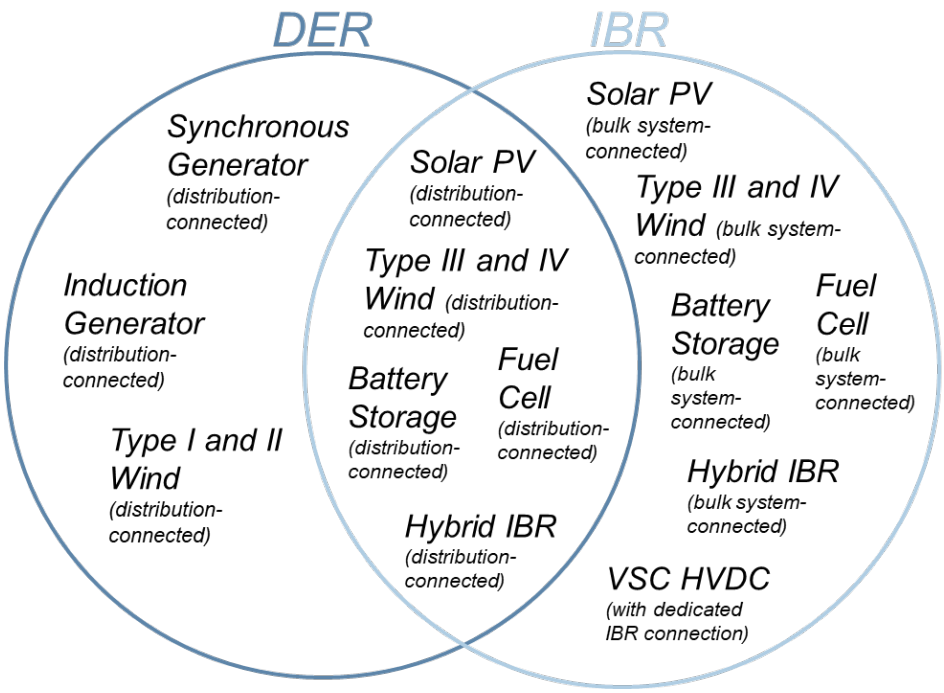


Figure 2: DER and IBR Definition Compatibility

Rationale for Modifications to Requirement R1

Requirement R1, Part 1.1 was modified to require that the PC and TP data requirements and reporting procedures include the responsible entity for data items listed in Attachment 1. To be clear, the "entity" to be identified would be the entity type or category (i.e., Transmission Owner), not specific companies for each data item. This modification aligns with changes made to the introductory paragraph in Attachment 1 clarifying that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The intention of this addition is not to create an administrative requirement for the PC and TP to maintain separate lists identifying entity obligations, but to reinforce PC/TP authority to request data from appropriate entities, thereby creating obligations for those entities to provide the requested data. In most cases, it is expected that data requirements and reporting procedures would inherently identify the entities required to provide data. Further, this modification is intended to give the PC/TP flexibility to identify (and specify within their data requirements and reporting procedures) the best source for necessary data, even if that source is not a NERC functional entity. However, only NERC functional entities are subject to mandatory compliance with NERC Reliability Standards, so the PC/TP is unlikely to assign other entities without a local authority to create data obligations outside of NERC enforcement. Such flexibility could allow the TP or PC to directly estimate data for an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes and aggregated DERs connected to unregistered Distribution Providers based on any information received in accordance with their data requirements and reporting procedures. As an example, data received from DPs in the area that can be assumed to have similar DER adoption profiles. FERC Order 901 uses the phrase "unregistered IBR" but given this is an undefined term and the drafting team received opposition to explaining that term in a footnote, the phrase was replaced in the standard with "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes." This is the intent of all further references to "unregistered IBR" in this technical rationale.

FERC Order 901 directs NERC to develop reliability standards that require "the use of approved industry generic library IBR models".[4] However, pre-defining a limited set of models (i.e., a library of models) that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To align with industry practices while addressing the directives of the FERC Order, the DT referenced standard library models incorporated within software as well as usability requirements for user-defined models (where accepted) in Requirement R1, Part 1.4, rather than defining an inclusive model library. The DT supports the approach and views it as aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 and June 3-5 NERC Industry Engagement Workshops.[5][6] For instance, Order 901 P125 requires "the sole use of nation-wide approved component generic library models" whereas workshop participants raised issues surrounding timelines for approving library models that reflect new IBR products, the accuracy of library models for certain products, timelines associated with updating library models, and referencing a document outside of the standard that could be changed by a process also outside the standard, among other issues.

[4] FERC Order 901 at Paragraph 122.
[5] NERC Industry Engagement Workshop–Reliable IBR Integration and Milestone 3 of FERC Order 901 Agenda
[6] Milestone 3 of FERC Order 901 NERC Industry Engagement Workshop June 3-4 PowerPoint

To address these concerns, Requirement R1, Part 1.4 includes requirements for the PC/TP to specify submission of standard library dynamic models, user-defined models, or both. The phrase user-defined models should be considered interchangeable with user-written models, equipment-specific models, and other such terms. The phrase "user-defined models" was used in MOD-032-2 based on language in FERC Order 901.[7] Allowing the specification of standard library models incorporated within modeling software is responsive to FERC concerns about usability and allows PCs to maintain current requirements for generic models that may be necessary for the creation of large Interconnection-wide base cases. Allowing the specification of user-defined models is responsive to industry feedback expressed during the NERC Industry Engagement workshops. The DT also explicitly ensured PC/TP authority to require submission of both model types, if deemed necessary. Requirement R1, Part 1.4.2 is responsive to FERC concerns about model usability and non-convergence by requiring PCs and TPs that accept user-defined models to specify usability requirements and require appropriate model documentation and instructions.

Rationale for Modifications to Requirement R2

Requirement R2 was modified to require estimation of modeling data if the functional entity required to provide it (typically the Transmission Owner or Distribution Provider) is unable to gather the required data. FERC Order 901 requires the provision of data related to unregistered-IBR and IBR-DER that in the aggregate have a material impact on the BPS.[8] If the data is estimated, Requirement R2 Part 2.1 also requires the entity to provide an explanation of the limitations of the estimated data and the method used for estimation in line with the Order 901 directives.[9] The requirement language intentionally uses the phrase "unable to gather" to mirror the FERC Order 901 language. Limitations of the estimated data is intended to capture both limitations of the availability of data (including instances where there are legal or contractual prohibitions on requesting certain data, no mechanism to enforce collection, or incomplete records of what is connected) and limitations of any data provided (including partially missing or suspect data).

The exact method used for estimation is intentionally left open given the varying levels of data available across the ERO footprint. A few possible examples include:

- A full list of DERs broken down by resource type with limited fields missing and assumed based on other characteristics.
- Real Power capability by resource type with approximate percentage of the resource compliance with various IEEE 1547 versions used for dynamic performance assumptions (known or assumed based on installation date).
- Count of resources by resource type with average size used to estimate Real Power capability.
- Derive values for unregistered DPs based on average of registered DPs in the area (scaled based on total system size).

[7] FERC Order 901 at P124
[8] FERC Order 901 at P104 and P105
[9] FERC Order 901 P104: "if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation."

- Solar capability estimated based on satellite imagery of rooftops.
- Assumptions of regional/national average IBR-DER penetration levels.

Additional guidance for DER estimation can be found in NERC SPIDERWG Reliability Guidelines on the topic.[10]

The DT views the introduction of this estimation provision as alleviating previously expressed compliance obligation concerns around challenges in collecting data for DERs connected to unregistered entities. Further, the addition of compliance abeyance language for the estimation process provides entities the opportunity to hone their estimation process without risk of penalty (provided they proceed in good faith). The approach directed by FERC is flexible as to whether the underlying unregistered IBR and DER data originates from interconnection documentation, measured quantities, estimated quantities, or other sources. Data availability or sufficiency issues, among other factors, may lead to the DP and TO applying a combination of approaches to source the data. The PC and TP modeling data requirements and reporting procedures should identify acceptable methods and their application.

While the FERC Order 901 directives only addressed IBR-DER, meaning that DER technologies based on induction generators or synchronous generators are not explicitly addressed, Project 2022-02 is also assigned a SAR that requires DERs to be addressed in MOD-032 more generally, and the inclusion of all DERs in this revision of the standard removes the need for a second modification under this project. The DT found it practical to have a consistent estimation framework applicable for all DER technologies when DER data cannot be gathered. Therefore, Requirement R2 was intentionally written to have requirements for estimating DER data regardless of the technology type, when an applicable entity is unable to gather the data. The approach FERC directed NERC to use forms the basis for this uniform approach.

Given the challenges with collecting complete and accurate DER data, the DT would still recommend that NERC consider a range of options that could include expanding DP registration criteria or registering DER-only DPs to reduce or eliminate this potential DER data collection gap. However, the process to modify NERC registry criteria and register new entities is beyond the scope of Project 2022-02 and would delay the project beyond the FERC Order 901 Milestone 3 timeline. The DT considered adding "UFLS-Only Distribution Provider" to MOD-032-2 applicability to reduce (but not necessarily eliminate) the potential gaps associated with DER connected to unregistered entities with no compliance obligation. However, the UFLS-Only Distribution Provider can only be obligated to provide data directly associated with UFLS programs (essentially the data identified in Attachment 1 Dynamics Column 10b). Provision of such data in the absence of the other DER data identified in Attachment 1 would not be particularly useful for planners.

Requirement R2, Part 2.2 was added to confirm the relationship and consistency between MOD-026 and MOD-032 indicated in FERC Order 901 Paragraph 143[11]. The DT believes that the intent of FERC Order 901

[10] Reliability Guidelines, Security Guidelines, Technical Reference Documents, and White Papers

[11] FERC Order 901 P143: ""Regarding EPRI's recommendation to require appropriately parameterized plant models, we agree that the model verification process of an IBR model should include steps to ensure that responsible entities provide both verified and appropriately parameterized models. Additionally, we agree with IRC's recommendation that the plant model verification process should include

is to ensure that accurate (validated and verified) models are collected under MOD-032. However, facility models submitted under MOD-032 are often submitted before physical validation can be completed (e.g., for planned facilities). Part 2.2 requires the model submitted by the functional entity be the model that was verified and validated (and accepted by the TP) in accordance with MOD-026, if available.

Requirement R2, Part 2.3 introduces a reference to the Unacceptable Models List (UML) maintained by the ERO. The DT concluded that it would be most appropriate for NERC to maintain the UML as a separate document that could be updated more quickly and frequently than the standard development process. However, any changes to the process for modifying the UML, that is incorporated into MOD-032-2 as a supporting document, would need to be approved through the standard development process.

It is also recognized that models on the UML may be the best available for some generators, particularly for some synchronous generators and for units manufactured by companies that are no longer in business. Part 2.3 allows for the submission of such a model if accompanied by a technical rationale justifying its use. The requirement does not intend any specific level of scrutiny for this rationale, but it also does not prevent the PC or TP from identifying technical concerns with the model or the rationale per Requirement R3. This rationale could include notation of prior usage for synchronous generation as well as models that have been recently added to the UML without time to procure an updated model prior to reporting. A MOD-032 supporting document defines the process for modifying the UML as a sufficient safeguard to prevent arbitrary or unvetted modifications being made to the UML.

Rationale for Modifications to Requirement R3

Requirement R3, Part 3.1 was modified to include the phrase “that is responsive to the technical concern”. The ultimate intent of R3 is to resolve technical concerns that are identified by the PC or TP. However, model providers may not always be able to know that their update or explanation will resolve the planner’s technical concern. The intent of this addition is to convey that the model provider’s obligation does not simply end with providing a response, but further information exchanges between the planner and model provider may be necessary to resolve the technical concern.

Rationale for Modifications to Attachment 1

Data items specific to IBRs and DERs were added to MOD-032-2 Attachment 1: Data Reporting Requirements.

The DT decided to maintain an approach similar to MOD-032-1 where more detailed sub-bullets associated with items are only presented in one column (i.e., some sub-bullets are only listed in the “steady state” column even though the data is also relevant to “dynamics” and/or “short circuit”). This long-standing approach was made explicit in footnote 1 of the MOD-032-2 Reliability Standard.

requirements for equipment to be represented as installed in the field. While we decline to include this level of detail in the directive to NERC, we nonetheless direct NERC to establish a standard uniform model verification process. A uniform model verification process will ensure that all entities use the same set of minimum requirements to verify that all generation resource (i.e., synchronous and non-synchronous) models are complete and that the models accurately represent the dynamic behavior of all generation resources at a sufficient level of fidelity for Bulk-Power System planners and operators to perform valid interconnection-wide, planning, and operational studies. Therefore, we direct NERC to define the model verification process and to require consistency among the model verification processes for existing Reliability Standards (e.g., FAC-002, MOD-026, and MOD-027) and any new or modified Reliability Standards.”

The format of Attachment 1 was modified to minimize replicating footnotes applicable to multiple items by adding a new footnotes section (Attachment 1 Data Reporting Requirements Footnotes) to the document. Along with the reformatting, language was added to the introductory paragraph to clarify that data obligations are established by the PC/TP modeling data requirements and reporting procedures rather than the listing of typical functional entities in Attachment 1. The expectation is that existing reporting requirements will remain the same, but previously implied flexibility is now explicitly granted as it is critical for regional consideration of the appropriate entities to provide information for unregistered IBR and DER.

Modifications for IBR

To incorporate IBR within Attachment 1, "and storage units" was added to generating units in the steady-state column under item 3. "Generating units" already incorporates IBR generators such as solar and wind. Storage is typically not classified as a generation resource because it has no primary energy source and consumes more energy than it injects when considering losses. Therefore, the DT found it necessary to include storage explicitly. Footnote 4, associated with "Generating units and storage", was also updated to explicitly identify IBR as an applicable technology for the item and remove pumped storage now that storage is explicitly identified.

The dynamics column was updated to replace "photovoltaic systems" (PV) with "Inverter-Based Resources" under item 7. IBR encompasses PV, resulting in PV technology still being included under this new item.
The three following sub-items were added to dynamics item 7 based on specific language from the FERC Order 901, Paragraph 141.[12]

- IBR capabilities related to momentary cessation,
- Tripping, and
- Ride-through

"Frequency control" was added as a sub-item because frequency response of IBR is important for studying system reliability. For instance, a 2024 NERC Lessons Learned report shows how IBR frequency response can affect system performance.[13] Frequency control encompasses primary frequency response, fast frequency response (e.g., IEEE 2800-2022, Subclause 6.2), and potentially other frequency responsive controls (e.g., "grid-forming" virtual synchronous machine controls).

"Voltage control" was added to encompass reactive power and voltage control that may affect the dynamic or steady state performance of the plant. NERC's Level 3 Alert on Inverter-Based Resource Performance and Modeling, issued May 2025, contains Essential Action #1 indicating the importance of voltage control performance for normal and post-disturbance operations.[14]

[12] FERC Order 901, P141 states that IBR and IBR-DER data must include "momentary cessation and/or tripping, and all ride through behavior."
[13] NERC, Lessons learned, Incorrect IBR Primary Frequency Response Logic Caused Negative ACE. Available at: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20240501_Incorrect_IBR_Primary_Frequency_Response_Logic_Caused_Negative_ACE.pdf
[14] NERC, IBR Performance and Modeling, Level 3 Alert. May 2025. Available at: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/Level%203%20Alert%20Essential%20Actions%20IBR%20Performance%20and%20Modeling.pdf

In order to clarify dynamics item 6, "wind plant model", to not overlap with the new IBR item 7, type 1 and type 2 wind turbines are specifically called out under item 6. These technologies are not IBR.

Footnote 5 indicates that the PC/TP data requirements and reporting procedures need to account for IBRs that are not DERs and do not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes. It also indicates that the TO is typically responsible for such data.

Modifications for DERs

Item 9, "Aggregate Distributed Energy Resource (DER) data" was added to the steady state column with location, real power capability, and DER type (solar, battery, diesel generator, etc.) specified as required subitems. The DT selected these subitems as the minimum information needed to use data and make assumptions for power system modeling and analysis; the PC/TP have the authority to request additional data items as deemed necessary.

The intent is that relevant DER data be available and represented in models of the interconnected transmission system consistent with the NERC approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies. Specific data items listed for DER reflect the minimum information needed to reasonably represent DER in transmission system models. "Aggregate DER" is specified in item 9 to indicate aggregate DER data, rather than individual DER facilities, would be represented in most PC/TP study models.[15] The word "aggregate" was specifically added to Attachment 1 to clarify this point based on industry comments and to align with FERC Order 901. However, Requirement R1 provides the PC and TP great flexibility in developing data requirements and reporting procedures that align with local practices and needs, in addition to the required items listed in the Requirement R1 Parts. Given industry comments on DER data availability, and FERC Order 901 directives, a process is needed for estimating DER data when an entity is unable to gather it. The process for estimating those values is referenced in Requirement R2, Part 2.1.

Footnote 3, associated with "aggregate demand", was modified to clarify that the gross demand is needed at each load serving bus. Collecting and modeling a net demand that incorporates offsets due to output from DERs is not consistent with a modeling framework that explicitly represents DERs. Given the allowance for a PC/TP to specify a threshold per footnote 7, they may confirm gross demand can be assumed to be equivalent to net demand when the difference is under that established threshold. This should be clarified in the level of detail of information requested in Requirement R1, Part 1.2.2.

Dynamics item 5, previously "demand", was updated to be "aggregate demand" to be consistent with the steady state column and general industry practices of modeling load dynamics for aggregate demand (e.g., composite load model).

[15] In certain circumstances (e.g., a very large DER), a TP or PC may decide to represent the individual DER. However, the DT anticipates most DER information will be aggregated based on PC and TP planning practices.

Dynamics item 10 was updated to include "Aggregate Distributed Energy Resource (DER) data" along with the subitems: "parameters, settings, or capabilities related to momentary cessation, tripping, Ride-through, voltage control, and frequency control"; and "indication whether DERs are subject to tripping in conjunction with UFLS or UVLS".

Momentary cessation, tripping, and ride-through of aggregate DERs is needed for dynamics studies. For instance, NERC's Lessons Learned, LL20220401 "Distributed Energy Resource Performance Characteristics during a Disturbance" provided information following the loss of 300 MW of DERs following a system fault. The report indicated that:

> "There is a need to understand how distribution system connected generation, and loads will behave and how they can accurately be modeled under expected system contingencies. Entities should know the behavioral characteristics of DER inverters on their system (both new and old) as well as their number, capabilities, and locations and then report that information to their Balancing Authorities and Reliability Coordinators so their models can be accurate".

Voltage control of DERs can alter the exchange of reactive power between distribution and transmission systems and may affect the results of reliability studies. Examples are described in the approved Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources.

Frequency control must be accounted for because DER interconnection under different standards (e.g., IEEE 1547-2003 versus IEEE 1547-2018) have different frequency response characteristics that may affect dynamics study results. Frequency control in this case typically refers to the frequency-droop characteristic outlined in IEEE 1547-2018, Subclause 6.5.2.7 and adopted in many jurisdictions. However, should other DER frequency controls become common in industry, those would also fall under this category.

As described in the approved Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs, accurately representing DER tripping as part of UFLS operation is vital for designing and evaluating UFLS programs. Similarly, accurately representing DER tripping as part of UVLS operation is vital for designing and evaluating UVLS programs as described in the approved White Paper: DER Impact to Under Voltage Load Shedding Program Design. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, the proportion of aggregate DERs subject to each UVLS/UFLS tripping stage should be identified.

In response to comments, the DT added Footnote 7, which explicitly confirms the PC/TPs discretion to specify aggregation thresholds below which they do not consider DER data necessary to collect. Based on the 0 MVA threshold recommendation noted previously, this threshold should only be established following consideration of that DER Modeling Study Report[16].

Inferring DER Capabilities

[16] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

Item 10 in the dynamics column indicates that aggregate DER dynamics modeling data may need to be inferred due to data availability and practical limitations. As suggested in the approved Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies, the in-service date for DERs may be used as a proxy for the PC/TP to make reasonable assumptions about DER capabilities. For example, in a certain jurisdiction DERs installed after a specified date may be required to have a certain ride-through characteristic. Thus, the appropriate Ride-through characteristic representation for DERs in that area could be inferred by the in-service date of the DERs. However, the PC/TP modeling data requirements and reporting procedures may require the provision of alternative information to achieve the same purpose. PC/TP modeling data requirements and reporting procedures may also require more detail and/or additional information. In cases where the PC/TP data requirements and reporting procedures require aggregated DER data to be provided, it is expected that the proportion of aggregate DER amount with in-service dates before and after certain threshold dates would be needed (and specified in the PC/TP requirements) to make inferences regarding the overall aggregate DER response characteristics.

Entity responsibilities and coordination

Footnote 6 indicates that the PC/TP data requirements and reporting procedures need to account for situations where DERs are connected to the system of an unregistered DP. When a DER is connected through a registered DP (directly connected to that DP, connected to an unregistered DP that is connected to that DP, or behind the meter of an end-use customer of either) that DP is the typical responsible entity for collecting and providing the DER data. Further, the TO would be the typical responsible entity if there is no system owned by a registered DP between the DER connection point and TO system. This clarification is necessary to reduce the possibility of DERs on the system being unaccounted for by any entity. The DT was responsible for the FERC Order 901 directive requiring an entity to be identified when DERs had no registered DP. It is possible that a company that is a registered Generator Owner may also own resources that do not meet the criteria for registration. That would not change the responsible entity identified per R1, though the owner is encouraged to provide all relevant data to that responsible entity. This point applies broadly, where nothing in the standard is intended to preclude coordination among entities to make sure the responsible entity has the best available information to provide.

The PC/TP may have access to sufficient data for modeling certain DERs through alternative means (e.g., direct registration of DERs or DER aggregators in certain markets). In such cases, the DP (or TO) should not be obligated to provide duplicate DER modeling data, but care will be needed to ensure DERs are not double counted. The PC/TP modeling data requirements and reporting procedures should clearly identify if there are certain classifications of DERs that are excluded from the DP/TO obligation for providing DER modeling data. This in no way absolves a DP/TO from an obligation to provide DER data according to the data requirements and reporting procedures developed by its PC and TP under Requirement R1.

It should be noted that the MOD-032-2 modifications do not change the classification of unregistered IBRs or DERs to become BES facilities subject to NERC reliability standards. Instead, the modifications place a compliance obligation on NERC registered entities (typically DPs or TOs if identified as the responsible entity by the PC/TP) to provide basic information about unregistered IBRs or DERs that are connected to their systems so they can be properly represented in Interconnection-wide cases. There are already existing requirements for such entities to provide information about load connected to their systems. Like load,

unregistered IBRs and DERs are not generally considered to be BES facilities. However, BES reliability assessments require an accurate representation of aggregate load, unregistered IBR, and aggregate DER behavior. The modifications proposed in MOD-032-2 are intended to ensure sufficient data is available to the PC/TP so that appropriate unregistered IBR and DER representations can be included in their BES reliability assessments as required by FERC Order 901 and system planning needs.

IRO-010-6 – Reliability Coordinator Data Specification and Collection; and TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

The DT reviewed existing IRO-010 and TOP-003 versions and found that both standards had broad requirements language that encompassed generation and storage resources, including IBR as deemed necessary by the RC/TOP/BA. Nevertheless, to ensure no ambiguity that FERC Order 901 requirements are met, the DT included explicit references to IBR-specific data and parameters and pointed to the uniform framework through an alignment between planning and operations models.

Rationale for modifications to add "IBR-specific data and parameters"

The phrase "IBR-specific data and parameters" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.1
- TOP-003-8 Requirement R1, Part 1.1
- TOP-003-8 Requirement R2, Part 2.1

These modifications were made in response to FERC Order 901 directives related to the inclusion of IBRs in operations models.[17] The phrase "IBR-specific data and parameters" in the revised IRO-010-06 and TOP-003-8 is intended to reflect what FERC describes in the order as "IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions". Given that the definition of IBR has no voltage threshold, the addition of IBR-specific data and parameters is inclusive of IBR-DER as referenced in FERC Order 901 and demonstrated by the overlapping area of Figure 2.

Rationale for modifications to add reference to consistency with planning models

"Requirements for necessary model submissions to be consistent with the model submitted for planning purposes, subject to modifications for operation purposes, as applicable" was added to the following requirements:

- IRO-010-6 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R1, Part 1.5.3
- TOP-003-8 Requirement R2, Part 2.5.3

These modifications were made in response to FERC Order 901 directives related to usage of a uniform framework in the development of planning and operations models. Planning model submissions in accordance with MOD-032-2 will reflect this uniform framework, though additional standards or regional requirements may apply. Thus, requiring that operations model submissions be consistent with planning model submissions ensures that they also reflect the uniform framework as directed by FERC in Order 901. Simulation time constraints in an online operations environment may warrant a reduced model structure complexity; such models may differ from, but should still be consistent with, more complex modeling that is submitted under MOD-032. The inclusion of "as applicable" allows for variation as necessary for application in the operations horizon. For example, consistent models would not be appropriate if an

[17] FERC Order 901 Paragraph 122 and Paragraph 161

update was made to a planning model for known pending changes, which should not be reflected in the operations models prior to implementation.

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Consideration of FERC Order No. 901 Directives

Milestone 3: Project 2022-02 Uniform Modeling Framework for IBR
September 2025

On October 23, 2023, FERC issued a Final Rule, Order No. 901, directing the North American Electric Reliability Corporation (NERC) to develop new or modified Reliability Standards that address aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project has a FERC regulatory deadline of November 4, 2025. Below provides the directives from FERC Order 901 along with the drafting team's (DT's) consideration of the directives.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
P7. "… Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate…"	IRO-010 MOD-032 TOP-003	A timeline has been drafted to meet the regulatory deadline of November 4, 2025. Completed tasks listed below. • An industry workshop completed January 14-17, 2025. (outreach) • Many virtual DT meetings completed weekly from January – March 2025. (publicly posted) • In-person DT completed February 11-13, 2025. (publicly posted) • Industry Webinar March 6, 2025. (publicly posted) • DT outreach with trade groups and entities March 3-14, 2025 • Industry comment and ballot period April 17-May 16, 2025. (publicly posted)

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
		• A second industry workshop completed June 3-5, 2025. (publicly posted) • Many virtual meetings were completed weekly from May 19-July 23, 2025. • Industry outreach with trade groups and entities July 3-23, 2025. • Industry comment and ballot period August 8-September 10, 2025.
P76. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information, and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System. As several commenters indicate, ensuring the sharing of appropriate IBR modeling data is critical to create and maintain the models used in reliability studies, and in turn to ensure that Bulk-Power System transmission planners or operators are able to plan for, operate, and reliably integrate IBRs onto the Bulk-Power System."	IRO-010 MOD-032 TOP-003	**Theme:** Inverter-Based Resource (IBR) /Generator Owner to provide specific modeling data. IRO-010 and TOP-003: • While TOP-003 and IRO-010 allow any data to be requested, the DT felt it was important to add "IBR-specific data and parameters" specifically to IRO-010-6 Requirements R1, subpart 1.1 and TOP-003-8 Requirement R1, subpart 1.1 and Requirement R2, subpart 2.1 to ensure it is clear what data may be specifically requested to address FERC Order No. 901. In addition, IBR encompasses IBR-DER, and this information could be requested. • The DT considered adding a new subpart at the end of Requirement R1 (e.g., Part 1.6), but after reviewing requirement language, the DT determined the data and information lists within the existing subparts were the appropriate place to capture IBR-specific modeling data and parameters.

FERC Order No. 901 Directives		
Directive Language	**Standards Impacted**	**Consideration of Directives**
		MOD-032: • Generator Owner and Generator Operator – The DT decided to maintain applicability for just the Generator Owner and did not add Generator Operator as a functional entity to the applicability section. If data is needed from the Generator Operator, then the Generator Owner can reach out to the Generator Operator for necessary data via contractual obligations, etc. The DT does not find it necessary to require two applicable entities when one oversees the other. • The DT modified Attachment 1 to include generation and storage units, removed photovoltaic system (covered within IBR) and added Inverter-Based Resources. The wind turbine was updated for clarity that it is for Type 1 and Type 2, which is not included in the IBR definition.
P77. "With regard to AEU and ACP/SEIA's comments that the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners and operators, we believe that this request may already be addressed through each transmission planner's existing processes. For example, the New York Independent System Operator (NYISO) and CAISO both have processes for obtaining such data after demonstrating a need for the specific information requested and that the required information protection and non-disclosure agreements are signed. Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's	MOD-032	**Theme:** Information going from Transmission Owner to Generator Owner/Generator Operator (consider): MOD-032 • There is no specific requirement within MOD-032 that requires Transmission Owners to share data with the Generator Owners and Generator Operators (and such a requirement would not be aligned with the purpose of MOD-032). However, Transmission Planners and Planning coordinators have a framework where requests for data can be sent for inclusion for the Interconnection-wide models. At this time, the DT does not see a need for a requirement to be drafted requiring Transmission Owners to provide data to Generator Owners and Generator Operators. The DT believes this is most appropriately addressed

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suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." **P74.** "AEU and ACP/SEIA ask that, in addition to data provision requirements for generator owners and operators, the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners. For example, AEU explains that generator owners and operators also require data from transmission owners to support accurate modeling and performance, e.g., short circuit data, grid data for offshore wind, information on other power electronic devices around the IBR plant, and voltage harmonics. AEU adds that putting requirements on transmission owners would be consistent with revisions being developed for NERC's Modeling, Data, and Analysis (MOD) Reliability Standards."		through processes that exist outside of the MOD-032 Reliability Standard and concurs with the suggestion in P77 that these processes are already in place.
P78. "Commenters raised general concerns that mandating specific modeling and data submissions would reduce the flexibility and discretion of transmission planners and operators to identify the information they need. We find that, given the need for IBRs to operate in a predictable and reliable manner to ensure the reliable operation of the Bulk-Power System, it is necessary to establish uniform, minimum categories or types of data that must be provided so that Bulk-Power System planners and operators can predict the behavior of all IBRs. As discussed in more	MOD-032 TOP-003 IRO-010	**Theme:** Individual use of approved IBR models. (Uniform modeling framework) **Applicability:** Transmission Planner and Transmission Operator • Modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establish an improved uniform modeling framework. IBR has been included in Attachment 1 of MOD-032 under steady state (item 3), dynamics (item 7), and short circuit specifying the minimum types of IBR data and capabilities that need to be collected as required per FERC Order No. 901.

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detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions."		• Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.
P86. "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."**	TOP-003 IRO-010	**Theme:** Disturbance and monitoring (Consider) (real-time operations) **Applicability:** Generator Owner TOP-003/IRO-010 • TOP-003 and IRO-010 Reliability Standards are already structured in an open way so that any type of data needed can be requested at any time. In addition, transmission of information from the plant level is generally dealt with via interconnection agreements and does not rise to the level of a requirement being needed at this time. Lastly, PRC-028 PMU devices must be installed for every IBR installation. These additional monitoring devices will allow additional data requests related to those devices, if the applicable entities find that useful. Because of the two items above (the open method for data requests and the PRC-028 PMU devices), the standard balances the needs for the Transmission Operator to gather the data deemed necessary for reliability without uniform burden on all generating facilities.
P102. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal, with modification. Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1)	MOD-032 IRO-010 TOP-003	**Theme:** 1) Transmission Owner directed to provide data for unregistered IBR and 2) Distribution Provider directed to provide data for IBR-DER **Applicability:** Transmission Owner and Distribution Provider

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transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System."		• The DT focused on the MOD-032 standard to address this directive from FERC. The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the MOD-032 standard. In response to comments seeking more precision, the MOD-032 standard uses the phrase "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes" to refer to the IBR resources encompassed by the term "unregistered IBR" in Order No. 901. • While the DT agrees that the Transmission Owner would be the typical entity for providing unregistered IBR data and the Distribution Provider would be the typical entity to provide DER data (as noted in Attachment 1 of MOD-032), the DT modified the Requirement language in response to comments to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2. Determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System, requires engineering judgment and is not something that would be appropriate to precisely specify in a reliability standard. Thus, Attachment 1 footnote 7 was added to explicitly allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard), and to add references back to the MOD-032 standard. The DT determined that the IRO-010 and TOP-003 standards already included language in place to address IBR impacts.

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P104. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) Estimation, if not able to get data from unregistered IBRs, 2) an explanation of the limitations of the availability of data, 3) explanation of the limitations of any data provided by unregistered IBRs, and 4) method for estimation. (directive) **Theme 2:** Implement a process or mechanism by which Transmission Owners would receive modeling data and parameters. (consider) **Applicability:** TO • The DT added Requirement R2, Part 2.1 allowing the functional entity to use the method of estimation should it find itself in a place unable to gather unregistered IBR data or DER data. However, it must include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. • In addition, the DT added an explanation of the resources that are intended to be captured. In proposed MOD-032, "unregistered IBR" are described as IBRs that are not Distributed Energy Resources, as the DT proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as owning either category 1 or category 2 assets). As suggested by commenters, the DT has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application. • While previous drafts of the MOD-032 standard used the shorthand phrase "unregistered IBR" to establish consistency with FERC Order No. 901, with the more fulsome description of

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the reliability of the Bulk-Power System. To support this data collection, we further direct **NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."**		those resources in the footnote, the DT moved this description to the requirement text (in lieu of the phrase "unregistered IBR") in response to comments. • It is important to note that Order No. 901 predated the changes NERC made to the Rules of Procedure to ensure that the owners and operators of such IBR resources would be registered with NERC for mandatory compliance purposes. NERC does not register IBRs as resources, but rather the owners of such resources based on the registry criteria for Generator Owner and Generator Operator. There are two categories of each: owners and operators of BES Facilities (category 1 GOs/GOPs); and owners and operators of 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 (category 2 GOs/GOPs). In Order No. 901 parlance, ownership or operation of IBR resources meeting these criteria would require owner/operator registration and therefore would be considered "registered IBRs". In Order No. 901 parlance, ownership or operation of IBR resources that do not meet these criteria but are connected to a transmission system (i.e., are not Distributed Energy Resources) would not require owner/operator registration and therefore would be considered "unregistered IBR." • The DT discussed implementing a process or mechanism by which Transmission Owners would receive modeling data and parameters in depth. It was determined that if a TO is unable to gather data for unregistered IBRs and DERs, it is better to not

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		mandate a specific process for how Transmission Owners acquire or estimate data. Obtaining data for unregistered IBRs should not pose a significant challenge because such facilities are likely directly connected to a TO system and provision of necessary data should be specified in interconnection agreements or other contracts. Obtaining data for DERs would be more challenging as these facilities are connected to the TO system through a separate unregistered DP. In such cases, it is prudent to allow various estimation methods to be used. • The IRO-010 and TOP-003 Reliability Standards are drafted in a way that is open-ended and allows the respective applicable entities to request data needed. However, project 2022-02 DT added "Inverter-based Resource (IBR) specific data and parameters" to ensure it is clear that entities can request data when needed for operations assessments. To the extent modeling is needed, it should be consistent with modeling data provided under MOD-032 modeling framework. Therefore, the DT made changes to the IRO-010 and TOP-003 standards to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes under MOD-032, as applicable.
P105. "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. (Directive) **Theme 2:** Consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters. (Consider)

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modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."		**Applicability:** Distribution Provider The DT added a new Requirement R2, Part 2.1 that if the responsible entity is unable to gather unregistered IBR data (*see description above*) or DER data and provide it to the Transmission Planner and Planning Coordinator, as specified in the data requirements and reporting procedures developed under Requirement R1, the responsible entity shall provide an estimate of the modeling data and parameters and include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. The DT discussed the possible mechanism by which Distribution Providers would receive modeling data and parameters. The DT did not feel this rose to the level of a requirement as the Distribution Provider can ask for the modeling data and parameters from the respective entity.
P106. "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead	MOD-032 IRO-010 TOP-003	**Theme:** Who is the responsible entity when no registered DP of IBR-DER (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation. • After much deliberation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for collecting and providing data for DERs

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to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."		connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." • The DT asked industry the following question: "Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system?" Some commenters agreed that the TO is the correct entity who should gather data if there is no associated registered DP between the DER connection point and the TO system. However, many comments received stated that the TO has no authority to collect data, and the following entities would be better suited to gather the data needed: Registered DP, Balancing Authority, Planning Coordinator, LSE, Generator Owner, Transmission Operator, and Resource Planner. Based on this feedback, the DT modified the Requirement language to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2.
P108. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request	MOD-032 IRO-010 TOP-003	**Theme:** Minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers that are necessary to predict the behavior of all

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that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear. As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions. By contrast, we believe that a directive to task distribution providers as the appropriate registered entity to collect and share the modeling data and parameters of IBR-DERs in the aggregate is preferable to deferring to the stakeholder process as suggested by APS. The distribution provider, as the entity providing and operating the lines between the transmission and distribution systems, is the entity best situated to have access to the data necessary for accurate estimation and, other than Indicated Trade Associations that suggested the piecemeal approach already discussed above, no commenter identified other potential entities as an equally efficient option."		IBRs and to ensure that compliance obligations are clear (ERO Approved Acceptable Criteria for Models/IEEE1547 ref./modify req./Tech rationale) **Applicability:** Transmission Planners, Transmission Operators, Transmission Owners, and Distribution Providers • The DT added Requirement R1, Part 1.4 to specify dynamic model submission requirements in Planning Coordinator/Transmission Planner data requirements and reporting procedures. • The focus of Requirement R1 Part 1.4 is obtaining accurate and usable models for IBRs. New Requirement R2 Part 2.3 provides that models with known deficiencies, such that the ERO included them on the Unacceptable Model List, shall not be submitted without technical justification. • Attachment 1 was modified to categorize the types of data required as per the directive (IBR, aggregate DER, Storage) necessary to facilitate model development. • Requirement R2, Part 2.1 requires entities to estimate unregistered IBR and IBR-DER data if the entity responsible for providing such data is unable to gather it.
P122. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop	MOD-032 IRO-010	**Theme**: Require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-

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new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."	TOP-003	circuit, and dynamic conditions when developing planning, operations, and Interconnection-wide models. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the DT determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their Interconnection-wide models and subsequently their planning cases. The DT considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The DT further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

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		To bookend these criteria for acceptable models, proposed Requirement R2 would also require any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The Unacceptable Models List includes models that NERC has identified over time as having known issues. While the DT initially proposed to foreclose the use of such models, the DT considered feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The DT believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns. The DT debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the DT ultimately decided to include this requirement in Requirement R2 as it relates to how entities respond to data specifications. The DT has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or

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		remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the DT has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for entities for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff are currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.
P124. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and		**Theme:** Nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies. (Uniform Modeling framework)

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dynamics studies. We acknowledge NERC's comment that user-defined models may be helpful for specific local reliability studies; however, the user-defined model cannot be used in place of nation-wide approved component models for regional analysis or interconnection-wide analysis because the user-defined model may cause non-convergence and other issues. However, NERC may allow the submission of user-defined models alongside the approved industry generic IBR model. Various entities do not accept user-defined models or only accept them for limited instances along with the open-source code which then allows internal model components to be viewed and modified. For example, PJM does not accept user-defined models and requires generic models for model verification in accordance with currently effective Reliability Standards MOD-026-1 and MOD-027-1. NYISO accepts a user-defined model in limited instances but requires either the open-source code (allowing anyone to access the internal model) or dynamic link library data and code files (compiled code that must be decompiled to view the internal model) that must be supplied for existing power flow software and in perpetuity."		The uniform modeling framework established in the proposed MOD-032 will focus on the use and representation of positive sequence phasor domain (PSPD) models in registered entity footprints and in Interconnection-wide models. Interconnection-wide modeling may be different from the models used in specialized studies dedicated to a particular technical objective. The ERO Unacceptable Models List applies to the models where NERC Reliability Standards require its use (generally for planning and operation models where multiple entities share information beyond their portion of the electric system, which includes Interconnection-wide models). Further guidance for interconnection applications can be found in the *NERC Dynamic Model Recommendations*. The DT considered introducing an approved model list for use in building cases specifically for Interconnection-wide analysis through Requirement R1 Part R1.2 of the proposed MOD-032, however, pre-defining a limited set of models that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To meet this directive, the DT modified Requirement R1 of MOD-032 by specifying the use of standard library "generic" models in Interconnection-wide cases while allowing the use of user-defined models. This provision was careful to address typically reported issues associated with user-defined models (UDMs) including non-convergence, by requiring that TP/PCs establish usability requirements for UDMs while incorporating an open, transparent process of identifying deficient models through the use of the "MOD-032 Supporting Documentation – Process for Updating the Unacceptable Models List Maintained by the ERO" and the "ERO Unacceptable Model list". Any TPs/PCs accepting UDMs shall provide

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		their UDM requirements to other PCs/TPs within the Interconnection upon request. The DT believes this approach balances the practical limitations of "generic models" raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop with the need for an improved uniform modeling framework. The combination of specifying the use of standard library component models approved and offered by software simulation tools, along with the ERO maintained Unacceptable Model List and its processes, will ensure that models used in interconnection wide analysis are robust enough while accuracy is not compromised to any level of detail deemed necessary. The introductions to this framework increase the data specifications requirements when user-defined models are used. TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P125. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models. One example of a way NERC could meet this directive would be to require an equivalent generic library model along with all submissions of user-defined models so that the generic library model can be used when combining	MOD-032 IRO-010 TOP-003	**Theme:** Nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build Interconnection-wide models. (Uniform Modeling framework /Req language) • Nation-wide approved components via generic library models are addressed via the development of a framework established in the proposed MOD-032-2 through improvements to Requirements R1, R2, and R3. The inclusion of ERO Unacceptable Models List, MOD-032 Supporting Document, and additional

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neighboring transmission system models and in interconnection-wide models."		requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. • The PC and TP are allowed to require provision of generic models, but if equipment-specific models satisfy usability criteria, and processes established through Requirements R1, R2, and R3 of the proposed MOD-032 standard, they are not prohibited. The framework explicitly allows for the submission of equivalent generic library models along with submissions of user-defined models which allows for the use of generic library models when combining neighboring transmission system models and Interconnection-wide models. • TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P141. "We also direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior. Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to	MOD-032 IRO-010 TOP-003	**Applicability**: GO • Nation-wide approved components via generic library models are addressed via the modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establishing an improved uniform modeling framework. This approach is aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop. • MOD-032, Attachment 1 was modified to specifically add that capabilities related to momentary cessation, tripping, and Ride-

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create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives. Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior). Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on		through, be reflected in the required model data for IBR and DER. • Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.

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the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives. Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models. Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System."		
P146. Accordingly, **we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to**	MOD-032 IRO-010 TOP-003	**Theme**: IBR-DER Model • As per the directive, the DT is requiring the modeling of aggregate DER through requirement R1 and Attachment 1. The currently available DER_A model is sufficient only for positive sequence phasor domain simulations. With the variety of other simulation domains (such as EMT and short circuit) necessary to study IBRs, mandating this model could prevent TPs or PCs from

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be able to perform respective system studies. For example, the new or modified Reliability Standards could require models of IBR-DERs (i.e., DER_A model) to adequately reflect the steady-state and dynamic aggregate resource performance in both a transmission area and across the interconnection. Additionally, estimated modeling data and parameters of IBR-DERs that in the aggregate (i.e., DER_A model) have a material impact on the Bulk-Power System could be used where measured and collected data is not available. We believe requiring the DER_A model will address NERC's request for entities to work collaboratively with the state regulators to identify, implement, and perform an effective model validation approach for IBR-DERs in the aggregate as opposed to requiring validated models of IBR-DER in the aggregate that can have a material impact on the reliable operation of the Bulk-Power System.		performing their studies. This further reinforces the DT's election to not require the use of the DER_A model, but rather a model that achieves specific performance criteria and conforms with MOD-032 edits in Attachment 1 and Requirement R1. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, not Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection (rather than mandating use of a defined set of models). Specific fidelity/accuracy evaluations are beyond the scope of MOD-032. • The DT considered referencing the DER_A model specifically, but refrained due to the rapidly evolving nature of models and concerns for the time required to update such a reference in a NERC Standard. Additionally, the DT is not specifying particular library models for other resources, so specifying a particular model for DER will invite challenges. Further, challenges with precisely defining and determining what a "successor model" is could potentially create more future reliability risks. The standard as currently written allows for additional future models of higher fidelity to be accommodated.
P157. We believe the development of new or modified Reliability Standards is an important corollary to NERC's ongoing effort to identify and register generator owners and operators of IBRs. Although NERC's registration changes will not at this time address IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, we believe APS's concerns	MOD-032 TOP-003 IRO-010	**Theme:** The responsible entity for IBR-DER data when there is no registered DP. Upon a decent amount of conversation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for

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regarding system-wide model validation is addressed in NERC's Reliability Guidelines and through the use of the EPRI DER Settings Database. We recognize that some distribution providers may not be able to provide a precise set of modeling data and parameters that accurately represent IBR-DERs in the aggregate. For these situations, NERC has provided a technical means to estimate in aggregating the needed IBR-DER modeling data and parameters (i.e., for the DER_A model) in the IBR-DER Data Collection Guideline. Further, NERC's 2021 Aggregate DER Model Verification Guideline provides transmission planners and planning coordinators with tools and techniques that can be adapted for their specific systems to verify that aggregate DER models (i.e., DER_A models) are a suitable representation of these resources in planning assessments. **Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models.**		collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." The use of the word "typical" is intentional to indicate the most likely entity based on the DT's broad understanding but allows flexibility per Requirement 1 for the PC/TPs to select a more appropriate entity or entities in their area based on regional or jurisdictional differences.
P161. "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal to provide additional specificity to explain coordination and keep up to date in a timely manner the verified data and models of	MOD-032 IRO-010 TOP-003	The proposed Milestone 3 Reliability Standards collectively address the Commission's directives in Order No. 901 paragraph 161.

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registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate in the system models. **Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model.** Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these resources in the system models. For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity		The Project 2022-02 DT modified MOD-032 to ensure it captures the uniform framework with modeling criteria, and necessary data exchange requirements for registered IBR, unregistered IBR, and DER (to include IBR-DER). Modifications in TOP-003 and IRO-010 are intended to promote consistency in models submitted for planning purposes and operations purposes so that entities responsible for planning and operating the BPS are all working from similar models that accurately represent the resources within their footprints. • A uniform modeling framework is established in the proposed MOD-032-2 through improvements to R1, R2, and R3 and Attachment 1. The inclusion of the ERO Unacceptable Models List (and additional revision process) and additional requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. Where appropriate, there are flexibilities built into this framework to accommodate differences in planning area modeling needs. • The PC and TP are allowed to require standard library models, but if user-written models satisfy usability criteria, and processes established through R1, R2, and R3 of the proposed MOD-032-2 standard, they are not prohibited. The framework explicitly allows for the submission of standard library models along with submission of user-written models which allows for the use of standard library models when combining neighboring transmission system models and Interconnection-wide models. If user written models are accepted, the PC and TP are required to share their usability criteria with other planning entities within the Interconnection upon request.

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responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives. NERC may implement this directive by modifying Reliability Standards MOD-032-1 and MOD-033-2 or by developing new Reliability Standards to establish requirements mandating an annual process to coordinate, validate, and keep up-to-date the transmission planning, operations, and interconnection-wide models."		• The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the proposed MOD-032-2 standard. While the TO would be the typical entity for providing unregistered IBR data and the DP would be the typical entity to provide DER data (as noted in Attachment 1 of proposed MOD-032-2), the DT recognized that there may be some variations as to whom might have the most accurate and usable data for unregistered resources in the planning area. Therefore, the DT modified the Requirement language to allow the PC and each of its TPs to identify the most appropriate entity to provide the data listed in Attachment 1 of proposed MOD-032-2. • Similarly, a determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System requires engineering judgment and the consideration of other material factors, which would not be prudent to prescribe in a Reliability Standard. Thus, Attachment 1 footnote 7 of proposed MOD-032-2 was added to explicitly allow PCs/TPs to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard). To the extent IBR modeling data is deemed necessary under IRO-010 and TOP-003, it should be consistent with modeling data provided for planning purposes. Therefore, the DT made changes to IRO-010 and TOP-003 to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes. Consistency in models is important to ensure BPS planners and operators are working from similar and high quality models; however, the DT recognized that operations entities may

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		require some adjustments from the model submitted for planning purposes to satisfy the needs in an operations environment. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, rather than Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection, so that entities may select the most representative model for the resource meeting PC/TP requirements (rather than mandating use of a defined set of models which may quickly become out-of-date). Models that are known to have fidelity issues are not to be submitted without technical justification. Specific fidelity/accuracy evaluations are beyond the scope of MOD-032, but are addressed in other proposed Milestone 3 Reliability Sstandards. The DT confirmed the link between these standards by requiring that models submitted under MOD-032 shall be the models verified under MOD-026, where available. System models developedvalidated under MOD-033 shall be developedperformed in accordance with data provided under MOD-032 and MOD-033. Regarding thate part of the directive to keep models up to date, MOD-032-1 already mandated a "schedule for submission of data at least once every 13 calendar months." This requirement is maintained in proposed MOD-032-2. System models will thus be built on updated data and models, which are verified and validated in accordance with the proposed MOD-033-2 and MOD-026-2 standards. With regards to that part of the p.161 directive addressing a "registered model designee" for building the Interconnection-wide cases, NERC considered the directive and concluded that the present ERO modeling

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		designee framework, with notable enhancements since 2023, presents an equally effective and efficient alternative to designating an entity on the NERC Compliance Registry to perform the tasks of Interconnection-wide model building. Further, the present framework, as enhanced since 2023, has distinct advantages over designating a responsible entity in that it maintains ongoing oversight of the Interconnection case building process, rather than compliance/audit-focused oversight with a retroactive focus. Additional explanation is provided below. **Registered Modeling Designee:** The current MOD-032-1 Requirement R4 requires each PC to make available models for its planning area provided under R2 to the Electric Reliability Organization (ERO) or its designee to support the creation of the Interconnection-wide cases. This is not changed in proposed MOD-032-2 R4. As noted above, proposed MOD-032-2 Requirement R1, Part 1.1 would require the PC and each of its TPs to identify the entity responsible for each required item in Attachment 1. That entity must provide the information under Requirement R2. A new Requirement R2, Part 2.2 has been added to require models provided under MOD-026 to be accepted by the TP, where available Requirement R3 requires notification from the PC or TP regarding technical concerns with the data submitted under Requirement R2. This improved framework for modeling contemplates coordination and model updates as needed by registered entities as models are collected to build the Interconnection-wide cases. As to who builds the Interconnction-wide base case model, the ERO has designated entities with a sufficient wide area view and focus on reliability for each Interconnection to perform this work. For the Texas Interconnection, the Texas Regional Entity performs this work in

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		coordination with ERCOT. For the Western Interconnection, the Western Electric Coordinating Council (WECC) performs this work. For the Eastern Interconnection, the Eastern Interconnection Reliability Assessment Group (ERAG) consisting of MRO, NPCC, RF, and SERC performs this work. The ERAG also performs the base-case model creator function for the Quebec Interconnection in Canada. As the ERO, NERC is responsible for overseeing and ensuring that these designated entities perform the proposed MOD-032-2 Requirement R4 activities. In 2023, the Officers Leadership Team of the ERO Enterprise approved the MOD-032 Designee process document. This process document reflects the maturation of this aspect of the ERO's activities and contains clauses and processes that require the designee for the Interconnection to perform specific duties. Each designee must have certain attributes, including a governance structure responsive to the needs of Planning Coordinators, with clear roles and responsibilities for model creation, transparency in data requirements, establishing timeframes for review cycles, and defining security and access to models. Certain core cases are required as part of this process, including core cases for the ERO for use in seasonal planning studies and event analyses. Other core cases are required for validating Interconnection Frequency Response obligations and event analyses. Lastly, the process requires the development of typical cases to support implementation of the TPL-001 standard. NERC or the Regional Entities may request additional specialized cases as needed. Designated entities have certain responsibilities under this framework, including developing a method for collecting data from all Planning Coordinators and developing and maintaining a case creation manual

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		including the process by which cases must be assembled, tested for quality, and tested for case fidelity according to ERO case quality metrics. NERC will perform an annual case quality assessment, and the designee must address any case model deficiencies identified by NERC. The process also contemplates feedback processes and processes for correcting cases or addressing recurring data or model errors with Planning Coordinators, among other controls, to ensure quality. Regarding the ERAG, there is also an Eastern Interconnection Regional Entity Agreement among MRO, NPCC, RF, and SERC[1]. In this agreement, there are provisions for oversight and coordination in how this group exercises its authority as the MOD-032 designee. Connections to MOD-032 are acknowledged, such as: • Oversight of the Multiregional Modeling Working Group[2] (MMWG, whose membership is comprised of one power flow representative and one dynamics representative from each of the Data Submitting Entities (comprised of Planning Coordinators or group of Planning Coordinators) and non-voting representatives as follows: one liaison representative each of the EI Regions and the ERAG Chair, a coordinator from each of the organizations that provides model development services to MMWG, and NERC and FERC staff liaisons. ○ The purpose of the MMWG is to coordinate, in a timely manner, the development of designated power flow and

1 EI-Regional-Entity-Agmt-Final-Signed.pdf

2 ERAG-MMWG-Charter-2024.pdf

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		dynamics simulation base case models that realistically simulate steady state and dynamic bulk electric system behavior of the Eastern Interconnection. ○ To ensure cases and models are done in a consistent fashion, the MMWG holds three annual meetings along with conference calls as needed. The MMWG roster includes a FERC liaison who can attend all meetings. The group maintains a case building procedure manual[3] that is used by its members. The manual contains a set of data checks that are performed on the steady state and dynamic cases. • Oversight of the Acceptable Model Working Group (AMWG)[4], which is comprised of: (1) Planning Coordinators or group of Planning Coordinators who are responsible for the development and maintenance of an Eastern Interconnection dynamic acceptable model list, and (2) RE and NERC staff who are responsible for coordination and facilitation. ○ The group was formed in 2023 and recently published the first version of its acceptable model list which was posted to the public ERAG website[5]. As models are removed from the acceptable list, the group develops an industry communication to begin removing those models from the annual set of cases.

[3] Microsoft Word - ERAG Base Case Release Procedure

[4] https://www.rfirst.org/wp-content/uploads/2023/10/ERAG_AcceptableModel_WorkingGroup_Charter.pdf

[5] www.erag.info

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		○ Oversight includes review of all process changes made to the AMWG procedures to ensure consistency with the NERC case quality metrics. In addition, NERC further considered the following information provided by the MOD-032 Designee Group comprised of members from NERC and the Regional Entities: **MOD-032 Designee Group:** The electric grid is evolving at an unprecedented pace, driven by the rapid integration of inverter-based resources (IBRs), changing load characteristics, and emerging technologies. As the system transforms, the models we use to study and understand its behavior must also transform. We recognize the growing challenge of obtaining and coordinating accurate dynamic models for IBRs, including securing the appropriate parameters needed to ensure that simulation results reflect real-world system performance. Addressing these modeling challenges is essential to maintaining the reliability and resilience of the bulk power system and requires close collaboration, and the MOD-032 designees along with PCs are committed to and holding data providers accountable for model coordination and model quality. The MOD-032 designees are committed to ensuring that the model quality is maintained and there is a mechanism in place for the PC/TP to gather the appropriate information from the Generator Owners (GO). NERC facilitates the designee group of Regional Entity staff who are responsible for designee activities.

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		*** In summary, the proposed revisions to the standards addressed in Milestone 3 work, along with the ERO designated entity framework discussed above for building Interconnection-wide cases, address the concerns underlying the Commission's directive in paragraph 161 of Order No. 901 regarding the coordination, updating, and timely development of quality Interconnection-wide models that accurately represent the behavior of IBRs in the Interconnection. Further, this framework advances consistency in modeling used across planning and ERO assessment activities. NERC therefore submits that this framework represents an equally effective and efficient approach to addressing this part of the Commission's paragraph 161 directive to identify a registered modeling designee in the MOD-032 standard.
P226. "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	MOD-032 IRO-010 TOP-003	**Theme:** Sufficient timeframe. The DT felt that four years was an appropriate timeframe for the MOD-032, IRO-010, and TOP-003 implementation times. It is understood that based on what is required via MOD-032, industry would need two years to hold meetings with stakeholders to establish processes for collecting the needed models and data, and then an additional two years to update models based on the new requirements, etc. However, taking into consideration the FERC Order 901 implementation deadline of 2030, the DT settled on a three-year implementation time knowing that milestone 4 revisions still need to be implemented by 2030 and are dependent on the Milestone 3 implementation plan time. Three- year implementation plans were also selected for TOP-003 and IRO-010 to align potential new data requests under TOP-003 and IRO-010 with the expected data availability under MOD-032 processes.

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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."		

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of FERC Order No. 901 Directives

Milestone 3: Project 2022-02 Uniform Modeling Framework for IBR
September 2025

On October 23, 2023, FERC issued a Final Rule, Order No. 901, directing the North American Electric Reliability Corporation (NERC) to develop new or modified Reliability Standards that address aggregation of data, parameters, and estimation methods to provide the Transmission Planner (TP) and Transmission Operator (TOP) with the estimate values, explanation for limitations on data availability, and the method used for all estimations. This project has a FERC regulatory deadline of November 4, 2025. Below provides the directives from FERC Order 901 along with the drafting team's (DT's) consideration of the directives.

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P7. "… Second, by November 4, 2025, NERC must submit new or modified Reliability Standards addressing the interrelated directives concerning: (1) data sharing for registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate…"	IRO-010 MOD-032 TOP-003	A timeline has been drafted to meet the regulatory deadline of November 4, 2025. Completed tasks listed below. • An industry workshop completed January 14-17, 2025. (outreach) • Many virtual DT meetings completed weekly from January – March 2025. (publicly posted) • In-person DT completed February 11-13, 2025. (publicly posted) • Industry Webinar March 6, 2025. (publicly posted) • DT outreach with trade groups and entities March 3-14, 2025 • Industry comment and ballot period April 17-May 16, 2025. (publicly posted)

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		• A second industry workshop completed June 3-5, 2025. (publicly posted) • Many virtual meetings were completed weekly from May 19-July 23, 2025. • Industry outreach with trade groups and entities July 3-23, 2025. • Industry comment and ballot period August 8-September 10, 2025.
P76. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require registered IBR generator owners and operators to provide IBR-specific modeling data and parameters (e.g., steady-state, dynamic, and short circuit modeling information, and control settings for momentary cessation and ramp rates) that accurately represent the registered IBRs to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System. As several commenters indicate, ensuring the sharing of appropriate IBR modeling data is critical to create and maintain the models used in reliability studies, and in turn to ensure that Bulk-Power System transmission planners or operators are able to plan for, operate, and reliably integrate IBRs onto the Bulk-Power System."	IRO-010 MOD-032 TOP-003	**Theme:** Inverter-Based Resource (IBR) /Generator Owner to provide specific modeling data. IRO-010 and TOP-003: • While TOP-003 and IRO-010 allow any data to be requested, the DT felt it was important to add "IBR-specific data and parameters" specifically to IRO-010-6 Requirements R1, subpart 1.1 and TOP-003-8 Requirement R1, subpart 1.1 and Requirement R2, subpart 2.1 to ensure it is clear what data may be specifically requested to address FERC Order No. 901. In addition, IBR encompasses IBR-DER, and this information could be requested. • The DT considered adding a new subpart at the end of Requirement R1 (e.g., Part 1.6), but after reviewing requirement language, the DT determined the data and information lists within the existing subparts were the appropriate place to capture IBR-specific modeling data and parameters.

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		MOD-032: • Generator Owner and Generator Operator – The DT decided to maintain applicability for just the Generator Owner and did not add Generator Operator as a functional entity to the applicability section. If data is needed from the Generator Operator, then the Generator Owner can reach out to the Generator Operator for necessary data via contractual obligations, etc. The DT does not find it necessary to require two applicable entities when one oversees the other. • The DT modified Attachment 1 to include generation and storage units, removed photovoltaic system (covered within IBR) and added Inverter-Based Resources. The wind turbine was updated for clarity that it is for Type 1 and Type 2, which is not included in the IBR definition.
P77. "With regard to AEU and ACP/SEIA's comments that the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners and operators, we believe that this request may already be addressed through each transmission planner's existing processes. For example, the New York Independent System Operator (NYISO) and CAISO both have processes for obtaining such data after demonstrating a need for the specific information requested and that the required information protection and non-disclosure agreements are signed. Nevertheless, to support accurate modeling and performance, we direct NERC to consider during its standards development process AEU and ACP/SEIA's	MOD-032	**Theme:** Information going from Transmission Owner to Generator Owner/Generator Operator (consider): MOD-032 • There is no specific requirement within MOD-032 that requires Transmission Owners to share data with the Generator Owners and Generator Operators (and such a requirement would not be aligned with the purpose of MOD-032). However, Transmission Planners and Planning coordinators have a framework where requests for data can be sent for inclusion for the Interconnection-wide models. At this time, the DT does not see a need for a requirement to be drafted requiring Transmission Owners to provide data to Generator Owners and Generator Operators. The DT believes this is most appropriately addressed

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suggested data sharing requirements when developing the framework, criteria, and necessary data exchange requirements to meet the registered IBR data sharing directive." **P74.** "AEU and ACP/SEIA ask that, in addition to data provision requirements for generator owners and operators, the Commission direct NERC to specify data sharing requirements from transmission owners to generator owners. For example, AEU explains that generator owners and operators also require data from transmission owners to support accurate modeling and performance, e.g., short circuit data, grid data for offshore wind, information on other power electronic devices around the IBR plant, and voltage harmonics. AEU adds that putting requirements on transmission owners would be consistent with revisions being developed for NERC's Modeling, Data, and Analysis (MOD) Reliability Standards."		through processes that exist outside of the MOD-032 Reliability Standard and concurs with the suggestion in P77 that these processes are already in place.
P78. "Commenters raised general concerns that mandating specific modeling and data submissions would reduce the flexibility and discretion of transmission planners and operators to identify the information they need. We find that, given the need for IBRs to operate in a predictable and reliable manner to ensure the reliable operation of the Bulk-Power System, it is necessary to establish uniform, minimum categories or types of data that must be provided so that Bulk-Power System planners and operators can predict the behavior of all IBRs. As discussed in more	MOD-032 TOP-003 IRO-010	**Theme:** Individual use of approved IBR models. (Uniform modeling framework) **Applicability:** Transmission Planner and Transmission Operator • Modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establish an improved uniform modeling framework. IBR has been included in Attachment 1 of MOD-032 under steady state (item 3), dynamics (item 7), and short circuit specifying the minimum types of IBR data and capabilities that need to be collected as required per FERC Order No. 901.

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detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions."		• Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.
P86. "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."**	TOP-003 IRO-010	**Theme:** Disturbance and monitoring (Consider) (real-time operations) **Applicability:** Generator Owner TOP-003/IRO-010 • TOP-003 and IRO-010 Reliability Standards are already structured in an open way so that any type of data needed can be requested at any time. In addition, transmission of information from the plant level is generally dealt with via interconnection agreements and does not rise to the level of a requirement being needed at this time. Lastly, PRC-028 PMU devices must be installed for every IBR installation. These additional monitoring devices will allow additional data requests related to those devices, if the applicable entities find that useful. Because of the two items above (the open method for data requests and the PRC-028 PMU devices), the standard balances the needs for the Transmission Operator to gather the data deemed necessary for reliability without uniform burden on all generating facilities.
P102. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal, with modification. Specifically, as proposed in the NOPR, we direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that require: (1)	MOD-032 IRO-010 TOP-003	**Theme:** 1) Transmission Owner directed to provide data for unregistered IBR and 2) Distribution Provider directed to provide data for IBR-DER **Applicability:** Transmission Owner and Distribution Provider

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transmission owners to provide to Bulk-Power System planners and operators modeling data and parameters for unregistered IBRs in their transmission owner areas that, individually or in the aggregate, materially affect the reliable operation of the Bulk-Power System and (2) distribution providers to provide to Bulk-Power System planners and operators modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System."		• The DT focused on the MOD-032 standard to address this directive from FERC. The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the MOD-032 standard. In response to comments seeking more precision, the MOD-032 standard uses the phrase "an IBR that is not a DER and does not meet the criteria that would require the owner to register with NERC for mandatory Reliability Standards compliance purposes" to refer to the IBR resources encompassed by the term "unregistered IBR" in Order No. 901. • While the DT agrees that the Transmission Owner would be the typical entity for providing unregistered IBR data and the Distribution Provider would be the typical entity to provide DER data (as noted in Attachment 1 of MOD-032), the DT modified the Requirement language in response to comments to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2. Determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System, requires engineering judgment and is not something that would be appropriate to precisely specify in a reliability standard. Thus, Attachment 1 footnote 7 was added to explicitly allow Transmission Planners and Planning Coordinators to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard), and to add references back to the MOD-032 standard. The DT determined that the IRO-010 and TOP-003 standards already included language in place to address IBR impacts.

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P104. "Recognizing that there may be instances in which transmission owners are unable to gather adequate unregistered IBR modeling data and parameters to create and maintain unregistered IBR models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the unregistered IBR modeling data and parameters, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by unregistered IBRs, and (4) the method used for estimation. We believe that this directive appropriately balances commenters' concerns about data accessibility and burden with the established need for transmission owners to provide unregistered IBR modeling data and parameters to Bulk-Power System planners and operators in their transmission owner area. We recognize that estimated modeling data and parameters are approximations of actual modeling data and parameters. We further acknowledge that there is some degree of error in estimated modeling data and parameters. However, on balance we believe that requiring such estimates with explanation of any limitations is an improvement from not having any data at all; and that even estimates will increase the overall adequacy of models and improve	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) Estimation, if not able to get data from unregistered IBRs, 2) an explanation of the limitations of the availability of data, 3) explanation of the limitations of any data provided by unregistered IBRs, and 4) method for estimation. (directive) **Theme 2:** Implement a process or mechanism by which Transmission Owners would receive modeling data and parameters. (consider) **Applicability:** TO • The DT added Requirement R2, Part 2.1 allowing the functional entity to use the method of estimation should it find itself in a place unable to gather unregistered IBR data or DER data. However, it must include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. • In addition, the DT added an explanation of the resources that are intended to be captured. In proposed MOD-032, "unregistered IBR" are described as IBRs that are not Distributed Energy Resources, as the DT proposes to define that term, and that would not meet the criteria in the NERC Rules of Procedure to register the owner of the IBR for the Generator Owner functional entity registration (as owning either category 1 or category 2 assets). As suggested by commenters, the DT has removed the phrase "Bulk-Power System" from this description to remove any potential for ambiguity in application. • While previous drafts of the MOD-032 standard used the shorthand phrase "unregistered IBR" to establish consistency with FERC Order No. 901, with the more fulsome description of

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the reliability of the Bulk-Power System. To support this data collection, we further direct **NERC to consider commenters suggestions to implement a process or mechanism by which transmission owners would receive modeling data and parameters."**		those resources in the footnote, the DT moved this description to the requirement text (in lieu of the phrase "unregistered IBR") in response to comments. • It is important to note that Order No. 901 predated the changes NERC made to the Rules of Procedure to ensure that the owners and operators of such IBR resources would be registered with NERC for mandatory compliance purposes. NERC does not register IBRs as resources, but rather the owners of such resources based on the registry criteria for Generator Owner and Generator Operator. There are two categories of each: owners and operators of BES Facilities (category 1 GOs/GOPs); and owners and operators of 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 (category 2 GOs/GOPs). In Order No. 901 parlance, ownership or operation of IBR resources meeting these criteria would require owner/operator registration and therefore would be considered "registered IBRs". In Order No. 901 parlance, ownership or operation of IBR resources that do not meet these criteria but are connected to a transmission system (i.e., are not Distributed Energy Resources) would not require owner/operator registration and therefore would be considered "unregistered IBR." • The DT discussed implementing a process or mechanism by which Transmission Owners would receive modeling data and parameters in depth. It was determined that if a TO is unable to gather data for unregistered IBRs and DERs, it is better to not

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		mandate a specific process for how Transmission Owners acquire or estimate data. Obtaining data for unregistered IBRs should not pose a significant challenge because such facilities are likely directly connected to a TO system and provision of necessary data should be specified in interconnection agreements or other contracts. Obtaining data for DERs would be more challenging as these facilities are connected to the TO system through a separate unregistered DP. In such cases, it is prudent to allow various estimation methods to be used. • The IRO-010 and TOP-003 Reliability Standards are drafted in a way that is open-ended and allows the respective applicable entities to request data needed. However, project 2022-02 DT added "Inverter-based Resource (IBR) specific data and parameters" to ensure it is clear that entities can request data when needed for operations assessments. To the extent modeling is needed, it should be consistent with modeling data provided under MOD-032 modeling framework. Therefore, the DT made changes to the IRO-010 and TOP-003 standards to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes under MOD-032, as applicable.
P105. "We also recognize that there may be instances where distribution providers are similarly unable to gather adequate modeling data and parameters from IBR-DERs. Accordingly, to account for instances in which distribution providers are unable to gather adequate modeling data and parameters of IBR-DERs to create and maintain IBR-DER models, we modify the NOPR proposal and direct NERC to develop new or	MOD-032 IRO-010 TOP-003	**Theme 1:** 1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. (Directive) **Theme 2:** Consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters. (Consider)

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modified Reliability Standards that require that each distribution provider, if unable to gather accurate IBR-DERs data in the aggregate or unable to gather IBR-DERs data in the aggregate at all, provide instead to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs in the aggregate, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of the data provided by IBR-DERs, and (4) the method used for estimation. In support of above, we further direct NERC to consider commenters' suggestions to implement a process or mechanism by which distribution providers would receive modeling data and parameters."		**Applicability:** Distribution Provider The DT added a new Requirement R2, Part 2.1 that if the responsible entity is unable to gather unregistered IBR data (*see description above*) or DER data and provide it to the Transmission Planner and Planning Coordinator, as specified in the data requirements and reporting procedures developed under Requirement R1, the responsible entity shall provide an estimate of the modeling data and parameters and include an explanation of the limitations of the data provided for unregistered IBRs or DERs (limitations on the availability and of the data provided) and the method used for estimation. The DT discussed the possible mechanism by which Distribution Providers would receive modeling data and parameters. The DT did not feel this rose to the level of a requirement as the Distribution Provider can ask for the modeling data and parameters from the respective entity.
P106. "Finally, as noted by commenters, we recognize that there may be instances where IBR-DERs are connected to an entity that does not meet the criteria for registration with NERC as a distribution provider. For those areas with IBR-DERs that in the aggregate materially affect the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we direct NERC to determine the appropriate registered entity responsible for providing data of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, or, when unable to gather such accurate IBR-DERs data, to provide instead	MOD-032 IRO-010 TOP-003	**Theme:** Who is the responsible entity when no registered DP of IBR-DER (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation. • After much deliberation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for collecting and providing data for DERs

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to the Bulk-Power System planners and operators in their areas: (1) an estimate of the modeling data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, (2) an explanation of the limitations of the availability of data, (3) an explanation of the limitations of any data provided by the IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and (4) the method used for estimation."		connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DERs where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." • The DT asked industry the following question: "Do you agree that the Transmission Owner (TO) is typically the appropriate responsible entity for collecting and providing data for DER where there is no associated registered DP between the DER connection point and the TO's system?" Some commenters agreed that the TO is the correct entity who should gather data if there is no associated registered DP between the DER connection point and the TO system. However, many comments received stated that the TO has no authority to collect data, and the following entities would be better suited to gather the data needed: Registered DP, Balancing Authority, Planning Coordinator, LSE, Generator Owner, Transmission Operator, and Resource Planner. Based on this feedback, the DT modified the Requirement language to allow the Planning Coordinator and each of its Transmission Planners to identify the most appropriate entity to provide the data listed in Attachment 1 of MOD-032-2.
P108. "Regarding CAISO's concern regarding the potential "compliance trap" where planners and operators rely on third-party data and IRC's request	MOD-032 IRO-010 TOP-003	**Theme:** Minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers that are necessary to predict the behavior of all

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that the final rule specify the data to be submitted by all IBRs (i.e., registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate) and transmission devices using similar technologies, we direct NERC to determine through its standards development process the minimum categories or types of data that must be provided to transmission planners, transmission operators, transmission owners, and distribution providers necessary to predict the behavior of all IBRs and to ensure that compliance obligations are clear. As discussed in more detail in section IV.C of this final rule, we are also directing NERC to develop new or modified Reliability Standards that require the use of approved industry IBR models that accurately reflect the behavior of all IBRs during steady state, short-circuit, and dynamic conditions. By contrast, we believe that a directive to task distribution providers as the appropriate registered entity to collect and share the modeling data and parameters of IBR-DERs in the aggregate is preferable to deferring to the stakeholder process as suggested by APS. The distribution provider, as the entity providing and operating the lines between the transmission and distribution systems, is the entity best situated to have access to the data necessary for accurate estimation and, other than Indicated Trade Associations that suggested the piecemeal approach already discussed above, no commenter identified other potential entities as an equally efficient option."		IBRs and to ensure that compliance obligations are clear (ERO Approved Acceptable Criteria for Models/IEEE1547 ref./modify req./Tech rationale) **Applicability:** Transmission Planners, Transmission Operators, Transmission Owners, and Distribution Providers • The DT added Requirement R1, Part 1.4 to specify dynamic model submission requirements in Planning Coordinator/Transmission Planner data requirements and reporting procedures. • The focus of Requirement R1 Part 1.4 is obtaining accurate and usable models for IBRs. New Requirement R2 Part 2.3 provides that models with known deficiencies, such that the ERO included them on the Unacceptable Model List, shall not be submitted without technical justification. • Attachment 1 was modified to categorize the types of data required as per the directive (IBR, aggregate DER, Storage) necessary to facilitate model development. • Requirement R2, Part 2.1 requires entities to estimate unregistered IBR and IBR-DER data if the entity responsible for providing such data is unable to gather it.
P122. "Pursuant to section 215(d)(5) of the FPA, we adopt the NOPR proposal and direct NERC to develop	MOD-032 IRO-010	**Theme**: Require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-

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new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."	TOP-003	circuit, and dynamic conditions when developing planning, operations, and Interconnection-wide models. While FERC Order No. 901 directed NERC to "develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of all IBRs during steady-state, short-circuit, and dynamic conditions" (P 108), the DT determined to pursue an equally effective and efficient method for addressing what it believes is the overarching goal of this directive, which is to obtain IBR models that are accurate and usable by PCs/TPs for building their Interconnection-wide models and subsequently their planning cases. The DT considered that many entities have a different understanding for what is a "generic model", and that advancements in user-defined models have reduced some of the concerns identified by FERC in Order No. 901 and can be more accurate in representing the IBR. The DT further considered that NERC as the ERO does not presently maintain an "acceptable model library", but rather an "unacceptable model library", and it may prove practically difficult to keep an acceptable model library up to date in a timely fashion. Considering these factors, and the comments received, the proposed Requirement R1 revisions would allow flexibility to the PC/TP to define requirements for the submission of standard library models, user-defined models, or both. Where user-defined models are accepted, the TP/PC would need to include, at a minimum, requirements to provide documentation and instructions for model set up and use; these items would help minimize the risk of non-convergence, a concern identified by FERC for such models in Order No. 901.

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		To bookend these criteria for acceptable models, proposed Requirement R2 would also require any entity submitting a model on the Unacceptable Models List maintained by the ERO include a technical rationale supporting its use. The Unacceptable Models List includes models that NERC has identified over time as having known issues. While the DT initially proposed to foreclose the use of such models, the DT considered feedback that some of the models included on the present Unacceptable Models List may be the best or only option for representing certain legacy equipment, particularly synchronous equipment. The DT believes that requiring a technical rationale for using such models, while presenting some administrative burden to submitters, would advance the state of modeling overall consistent with the intent of Order No. 901 and would help ensure parity of requirements among generation types. Further, it would help ensure models with identified, known deficiencies are not being submitted without good reason. It is important to note that this requirement to submit a technical rationale for such models is not intended to supplant the process described in Requirement R3 for addressing model quality concerns. The DT debated the proper placement of this requirement at length, whether in Requirement R1 addressing TP/PC data specifications or Requirement R2, addressing how entities respond. After much discussion, the DT ultimately decided to include this requirement in Requirement R2 as it relates to how entities respond to data specifications. The DT has elected to maintain the Unacceptable Model List separately from the MOD-032, due to the need to maintain flexibility to add or

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		remove models in a faster manner than may be feasible under the NERC standard development process. To balance concerns about due process for mandatory and enforceable elements of standards, the DT has included in the MOD-032 standard a supporting document that describes the process that will be used to update the Unacceptable Model List. While the Unacceptable Models List will be maintained separately from the standard, the process itself would be considered part of the standard and subject to revision through the standard development process; however, the specific process steps would not be considered mandatory and enforceable requirements for entities for Reliability Standards compliance purposes. As described in that process, there are opportunities for public comment and technical vetting of specific model add/remove requests through the Reliability and Security Technical Committee. As part of this process, the RSTC would recommend an effective date for any changes, and the final recommendations would then be considered by the ERO and published on the NERC website. NERC staff are currently examining avenues for ensuring accessibility of this document as NERC transitions to a new website design in 2026. Any changes to the Unacceptable Models List would be communicated to industry and to the applicable governmental authorities so that entities using models added to/removed from the list would have multiple avenues to be made aware of their updated obligations and the relevant timing.
P124. "We direct NERC to determine through its standards development process which nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and		**Theme:** Nation-wide approved component models are needed to build IBR plant models for steady state, short-circuit, and dynamics studies. (Uniform Modeling framework)

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dynamics studies. We acknowledge NERC's comment that user-defined models may be helpful for specific local reliability studies; however, the user-defined model cannot be used in place of nation-wide approved component models for regional analysis or interconnection-wide analysis because the user-defined model may cause non-convergence and other issues. However, NERC may allow the submission of user-defined models alongside the approved industry generic IBR model. Various entities do not accept user-defined models or only accept them for limited instances along with the open-source code which then allows internal model components to be viewed and modified. For example, PJM does not accept user-defined models and requires generic models for model verification in accordance with currently effective Reliability Standards MOD-026-1 and MOD-027-1. NYISO accepts a user-defined model in limited instances but requires either the open-source code (allowing anyone to access the internal model) or dynamic link library data and code files (compiled code that must be decompiled to view the internal model) that must be supplied for existing power flow software and in perpetuity."		The uniform modeling framework established in the proposed MOD-032 will focus on the use and representation of positive sequence phasor domain (PSPD) models in registered entity footprints and in Interconnection-wide models. Interconnection-wide modeling may be different from the models used in specialized studies dedicated to a particular technical objective. The ERO Unacceptable Models List applies to the models where NERC Reliability Standards require its use (generally for planning and operation models where multiple entities share information beyond their portion of the electric system, which includes Interconnection-wide models). Further guidance for interconnection applications can be found in the *NERC Dynamic Model Recommendations*. The DT considered introducing an approved model list for use in building cases specifically for Interconnection-wide analysis through Requirement R1 Part R1.2 of the proposed MOD-032, however, pre-defining a limited set of models that could be used to represent generation and system components is potentially at odds with objectives to also have accurate models, especially as technology rapidly progresses. To meet this directive, the DT modified Requirement R1 of MOD-032 by specifying the use of standard library "generic" models in Interconnection-wide cases while allowing the use of user-defined models. This provision was careful to address typically reported issues associated with user-defined models (UDMs) including non-convergence, by requiring that TP/PCs establish usability requirements for UDMs while incorporating an open, transparent process of identifying deficient models through the use of the "MOD-032 Supporting Documentation – Process for Updating the Unacceptable Models List Maintained by the ERO" and the "ERO Unacceptable Model list". Any TPs/PCs accepting UDMs shall provide

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		their UDM requirements to other PCs/TPs within the Interconnection upon request. The DT believes this approach balances the practical limitations of "generic models" raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop with the need for an improved uniform modeling framework. The combination of specifying the use of standard library component models approved and offered by software simulation tools, along with the ERO maintained Unacceptable Model List and its processes, will ensure that models used in interconnection wide analysis are robust enough while accuracy is not compromised to any level of detail deemed necessary. The introductions to this framework increase the data specifications requirements when user-defined models are used. TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P125. "Accordingly, we direct NERC to develop new or modified Reliability Standards that require the sole use of nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build interconnection-wide models. One example of a way NERC could meet this directive would be to require an equivalent generic library model along with all submissions of user-defined models so that the generic library model can be used when combining	MOD-032 IRO-010 TOP-003	**Theme:** Nation-wide approved component generic library models for system models to facilitate the exchange of neighboring entities' respective planning and operation models and to build Interconnection-wide models. (Uniform Modeling framework /Req language) • Nation-wide approved components via generic library models are addressed via the development of a framework established in the proposed MOD-032-2 through improvements to Requirements R1, R2, and R3. The inclusion of ERO Unacceptable Models List, MOD-032 Supporting Document, and additional

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neighboring transmission system models and in interconnection-wide models."		requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. • The PC and TP are allowed to require provision of generic models, but if equipment-specific models satisfy usability criteria, and processes established through Requirements R1, R2, and R3 of the proposed MOD-032 standard, they are not prohibited. The framework explicitly allows for the submission of equivalent generic library models along with submissions of user-defined models which allows for the use of generic library models when combining neighboring transmission system models and Interconnection-wide models. • TOP-003 and IRO-010 proposed standards were modified to ensure models submitted are consistent with models submitted under the framework established in MOD-032.
P141. "We also direct NERC to require the generator owners of registered IBRs and the transmission owners that have unregistered IBRs on their system to provide to the Bulk-Power System planners and operators (e.g., planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities) dynamic models that accurately represent the dynamic performance of registered and unregistered IBRs, including momentary cessation and/or tripping, and all ride through behavior. Recognizing that there may be instances in which transmission owners are unable to gather accurate unregistered IBR modeling data and parameters to	MOD-032 IRO-010 TOP-003	**Applicability**: GO • Nation-wide approved components via generic library models are addressed via the modifications made to MOD-032, including incorporation of an ERO Unacceptable Models list, establishing an improved uniform modeling framework. This approach is aligned with the FERC Order directives while addressing the practical limitations raised by industry at the January 15-16 NERC Industry Engagement Workshop and re-iterated at the June NERC Industry Engagement Workshop. • MOD-032, Attachment 1 was modified to specifically add that capabilities related to momentary cessation, tripping, and Ride-

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create and maintain accurate unregistered IBR dynamic models in their transmission owner areas, we modify the NOPR proposal and direct NERC to develop new or modified Reliability Standards that require each transmission owner, if unable to gather accurate unregistered IBR data or unable to gather unregistered IBR data at all, to provide instead to the Bulk-Power System planners and operators in their areas, dynamic models of unregistered IBRs using estimated data in accordance with this final rule's section IV.B.3 data sharing directives. Further, we direct NERC to require distribution providers to provide to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities aggregated dynamic models that adequately represent the dynamic performance of IBR-DERs on their systems that in the aggregate have a material impact on the Bulk-Power System, including momentary cessation and/or tripping, and all ride through behavior (e.g., IBR-DERs in the aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior). Recognizing that there may be instances in which distribution providers are unable to gather data that accurately represents IBR-DERs in the aggregate, we modify the NOPR proposal and direct NERC to include in the proposed new or modified Reliability Standards a requirement that the distribution provider, if unable to gather data of IBR-DERs that in the aggregate have a material impact on		through, be reflected in the required model data for IBR and DER. • Explicit reference to IBR data was added to the TOP-003 and IRO-010 standards along with provisions to ensure that models submitted under these standards are consistent with the models submitted under the framework established in MOD-032.

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the Bulk-Power System, provide to the Bulk-Power System planners and operators (i.e., the data recipients) a dynamic model using estimated data for IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, in accordance with this final rule's section IV.B.3 data sharing directives. Furthermore, we acknowledge that there may be areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider. Therefore, we modify the NOPR proposal and direct NERC to determine the appropriate registered entity responsible for providing adequate data and parameters of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, and to identify the registered entities for coordinating, verifying, and keeping up to date the respective dynamic models. Finally, NERC must ensure that the proposed new or modified Reliability Standards account for the dynamic performance of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System."		
P146. Accordingly, **we direct NERC to develop new or modified Reliability Standards that require the use of the DER_A model or successor models to represent the behaviors of IBR-DERs that in the aggregate have a material impact on the Bulk-Power System at a sufficient level of fidelity for Bulk-Power System planners and operators to create valid planning and operations and interconnection-wide models and to**	MOD-032 IRO-010 TOP-003	**Theme**: IBR-DER Model • As per the directive, the DT is requiring the modeling of aggregate DER through requirement R1 and Attachment 1. The currently available DER_A model is sufficient only for positive sequence phasor domain simulations. With the variety of other simulation domains (such as EMT and short circuit) necessary to study IBRs, mandating this model could prevent TPs or PCs from

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be able to perform respective system studies. For example, the new or modified Reliability Standards could require models of IBR-DERs (i.e., DER_A model) to adequately reflect the steady-state and dynamic aggregate resource performance in both a transmission area and across the interconnection. Additionally, estimated modeling data and parameters of IBR-DERs that in the aggregate (i.e., DER_A model) have a material impact on the Bulk-Power System could be used where measured and collected data is not available. We believe requiring the DER_A model will address NERC's request for entities to work collaboratively with the state regulators to identify, implement, and perform an effective model validation approach for IBR-DERs in the aggregate as opposed to requiring validated models of IBR-DER in the aggregate that can have a material impact on the reliable operation of the Bulk-Power System.		performing their studies. This further reinforces the DT's election to not require the use of the DER_A model, but rather a model that achieves specific performance criteria and conforms with MOD-032 edits in Attachment 1 and Requirement R1. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, not Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection (rather than mandating use of a defined set of models). Specific fidelity/accuracy evaluations are beyond the scope of MOD-032. • The DT considered referencing the DER_A model specifically, but refrained due to the rapidly evolving nature of models and concerns for the time required to update such a reference in a NERC Standard. Additionally, the DT is not specifying particular library models for other resources, so specifying a particular model for DER will invite challenges. Further, challenges with precisely defining and determining what a "successor model" is could potentially create more future reliability risks. The standard as currently written allows for additional future models of higher fidelity to be accommodated.
P157. We believe the development of new or modified Reliability Standards is an important corollary to NERC's ongoing effort to identify and register generator owners and operators of IBRs. Although NERC's registration changes will not at this time address IBR-DERs that in the aggregate have a material impact on the Bulk-Power System, we believe APS's concerns	MOD-032 TOP-003 IRO-010	**Theme:** The responsible entity for IBR-DER data when there is no registered DP. Upon a decent amount of conversation, the DT determined that if there is no registered Distribution Provider, then the next best entity would be a Transmission Owner. The DT created a footnote to Attachment 1 stating: "The Distribution Provider is the typical responsible entity for

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regarding system-wide model validation is addressed in NERC's Reliability Guidelines and through the use of the EPRI DER Settings Database. We recognize that some distribution providers may not be able to provide a precise set of modeling data and parameters that accurately represent IBR-DERs in the aggregate. For these situations, NERC has provided a technical means to estimate in aggregating the needed IBR-DER modeling data and parameters (i.e., for the DER_A model) in the IBR-DER Data Collection Guideline. Further, NERC's 2021 Aggregate DER Model Verification Guideline provides transmission planners and planning coordinators with tools and techniques that can be adapted for their specific systems to verify that aggregate DER models (i.e., DER_A models) are a suitable representation of these resources in planning assessments. **Furthermore, for those areas with IBR-DERs in the aggregate that materially impact the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity responsible for the data and parameters of IBR-DERs in the aggregate and to establish a process that requires identified registered entities to coordinate, validate, and keep up to date the system models.**		collecting and providing data for DERs connected to its system either directly or through an unregistered Distribution Provider (i.e., not included on the NERC Compliance Registry) with no other registered entity systems between the DER connection point and the Distribution Provider's system. The Transmission Owner is the typical responsible entity for collecting and providing data for DER where there is no associated registered Distribution Provider between the DER connection point and the Transmission Owner's system." The use of the word "typical" is intentional to indicate the most likely entity based on the DT's broad understanding but allows flexibility per Requirement 1 for the PC/TPs to select a more appropriate entity or entities in their area based on regional or jurisdictional differences.
P161. "Pursuant to section 215(d)(5) of the FPA, we modify the NOPR proposal to provide additional specificity to explain coordination and keep up to date in a timely manner the verified data and models of	MOD-032 IRO-010 TOP-003	The proposed Milestone 3 Reliability Standards collectively address the Commission's directives in Order No. 901 paragraph 161.

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registered IBRs, unregistered IBRs, and IBR-DERs in the aggregate in the system models. **Specifically, we direct NERC to develop new or modified Reliability Standards that require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to establish for each interconnection a uniform framework with modeling criteria, a registered modeling designee, and necessary data exchange requirements both between themselves and with the generator owners, transmission owners, and distribution providers to coordinate the creation of transmission planning, operations, and interconnection-wide models (i.e., system models) and the validation of each respective system model.** Further, we direct NERC to include in the new or modified Reliability Standards a requirement for generator owners, transmission owners, and distribution providers to regularly update and communicate the verified data and models of registered IBRs, unregistered IBRs, and IBR-DERs by comparing their resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy for inclusion of these resources in the system models. For those areas with IBR-DERs in the aggregate that have a material impact on the reliable operation of the Bulk-Power System but do not have an associated registered distribution provider, we modify the NOPR proposal to direct NERC to determine the appropriate registered entity		The Project 2022-02 DT modified MOD-032 to ensure it captures the uniform framework with modeling criteria, ~~a registered modeling designee,~~ and necessary data exchange requirements for registered IBR, unregistered IBR, and DER (to include IBR-DER). Modifications in TOP-003 and IRO-010 are intended to promote consistency in models submitted for planning purposes and operations purposes so that entities responsible for planning and operating the BPS are all working from similar models that accurately represent the resources within their footprints. • A uniform modeling framework is established in the proposed MOD-032-2 through improvements to R1, R2, and R3 and Attachment 1. The inclusion of the ERO Unacceptable Models List (and additional revision process)~~, MOD-032 Supporting Document,~~ and additional requirement language aims to ensure uniformity in processes and models to facilitate the exchange of neighboring entities' respective planning/operation models and to build Interconnection-wide models. Where appropriate, there are flexibilities built into this framework to accommodate differences in planning area modeling needs. • The PC and TP are allowed to require ~~provision of~~ standard library models, but if user-written models satisfy usability criteria, and processes established through R1, R2, and R3 of the proposed MOD-032-2 standard, they are not prohibited. The framework explicitly allows for the submission of standard library models along with submission of user-written models which allows for the use of standard library models when combining neighboring transmission system models and Interconnection-wide models. If user written models are accepted, the PC and TP are required to share their

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responsible for the models of those IBR-DERs and to determine the registered entities responsible for updating, verifying, and coordinating models for IBR-DERs in the aggregate to meet the system models directives. NERC may implement this directive by modifying Reliability Standards MOD-032-1 and MOD-033-2 or by developing new Reliability Standards to establish requirements mandating an annual process to coordinate, validate, and keep up-to-date the transmission planning, operations, and interconnection-wide models."		usability criteria with other planning entities within the Interconnection upon request. • The DT added IBRs (including unregistered-IBRs) and DER (including IBR-DER) to Attachment 1 of the proposed MOD-032-2 standard. While the TO would be the typical entity for providing unregistered IBR data and the DP would be the typical entity to provide DER data (as noted in Attachment 1 of proposed MOD-032-2), the DT recognized that there may be some variations as to whom might have the most accurate and usable data for unregistered resources in the planning area. Therefore, the DT modified the Requirement language to allow the ~~Planning Coordinator~~PC and each of its ~~Transmission Planners~~TPs to identify the most appropriate entity to provide the data listed in Attachment 1 of proposed MOD-032-2. • Similarly, ~~Determination~~ a determination if an unregistered IBR or aggregate IBR-DER would "materially affect" the Bulk-Power System~~,~~ requires engineering judgment and the consideration of other material factors, which would not be ~~is not something that would be appropriate~~prudent to prescribe ~~to precisely specify~~ in a ~~reliability~~ Reliability ~~standard~~Standard. Thus, Attachment 1 footnote 7 of proposed MOD-032-2 was added to explicitly allow ~~Transmission Planners and Planning Coordinators~~PCs/TPs to specify DER thresholds that may be appropriate when considering impact to their local areas. • The DT made changes to the IRO-010 and TOP-003 standards to include IBRs specifically (see R1 of each standard). To the extent IBR modeling data is deemed necessary under IRO-010 and TOP-003, it should be consistent with modeling data provided for planning purposes. Therefore, the DT made changes to ~~the~~ IRO-010 and TOP-

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		003 ~~standards~~ to require that model submissions for operations purposes under IRO-010 and TOP-003 are consistent with the model submissions for planning purposes. Consistency in models is important to ensure BPS planners and operators are working from similar and high quality models; however, the DT recognized that operations entities may require some adjustments from the model submitted for planning purposes to satisfy the needs in an operations environment. The fidelity/accuracy components of the FERC directives were generally considered to be within the SAR scopes for Projects 2020-06 and 2021-01, ~~not~~ rather than Project 2022-02. However, the model framework established with the proposed MOD-032-2 does facilitate model fidelity and accuracy by allowing flexibility in model selection, so that entities may select the most representative model for the resource meeting PC/TP requirements (rather than mandating use of a defined set of models which may quickly become out-of-date). Models that are known to have fidelity issues are not to be submitted without technical justification. Specific fidelity/accuracy evaluations are beyond the scope of MOD-032, but are addressed in other proposed Milestone 3 Reliability Sstandards. The DT confirmed the link between these standards by requiring that models submitted under MOD-032 shall be the models verified under MOD-026, where available. System models developedvalidated under MOD-033 shall be developedperformed in accordance with data provided under MOD-032 and MOD-033. Regarding thate part of the directive to keep models up to date, MOD-032-1 already mandated a "schedule for submission of data at least once every 13 calendar months." This requirement is maintained in proposed MOD-032-2. System models will thus be built on updated data and

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		models, which are verified and validated in accordance with the proposed MOD-033-2 and MOD-026-2 standards. With regards to that part of the p.161 directive addressing a "registered model designee" for building the Interconnection-wide cases, NERC considered the directive and concluded that the present ERO modeling designee framework, with notable enhancements since 2023, presents an equally effective and efficient alternative to designating an entity on the NERC Compliance Registry to perform the tasks of ~~model designee for~~ Interconnection-wide model building ~~that is a registered entity~~. Further, ~~this~~ the present framework, as enhanced since 2023, has distinct advantages over designating a responsible entity in that it maintains ongoing oversight of the Interconnection case building process, rather than compliance/audit-focused oversight with a retroactive focus. Additional explanation is provided below. **Registered Modeling Designee:** The current MOD-032-1 Requirement R4 requires each PC to make available models for its planning area provided under R2 to the Electric Reliability Organization (ERO) or its designee to support the creation of the Interconnection-wide cases. This is not changed in proposed MOD-032-2 R4. As noted above, proposed MOD-032-2~~,~~ Requirement R1, Part 1.1 would require~~s~~ the ~~Planning Coordinator (~~PC~~)~~ and each of its ~~Transmission Planners (~~TPs~~)~~ to identify the ~~Entity~~ entity responsible for each required item in Attachment 1. That entity must provide the information under Requirement R2. ~~Requirement R3 requires notification from the PC or TP regarding technical concerns with the data submitted under Requirement R2. Additionally, a~~ A new Requirement R2, Part 2.2 has been added to require models provided under MOD-026 to be accepted by the ~~Transmission Planner~~TP, where available~~.~~

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		Requirement R3 requires notification from the PC or TP regarding technical concerns with the data submitted under Requirement R2. ~~This allows a more detailed model that has also been verified to receive a review and coordination in order to be accepted by the TP. These requirements~~This improved framework for modeling contemplates coordination and model updates as needed by registered entities as models are collected to build the Interconnection-wide cases. ~~allow for the coordination and model updates needed by registered entities.~~ ~~In addition, Requirement R4 requires each PC to make available models for its planning area under R2 to the Electric Reliability Organization (ERO) or its designee to support the creation of the Interconnection-wide cases.~~As to who builds the Interconnction-wide base case model, ~~T~~the ERO has designated ~~Entities~~ entities with a sufficient wide area view and focus on reliability for each Interconnection to perform this work. For the Texas Interconnection, the ~~, such as~~ Texas Regional Entity performs this work in coordination with ERCOT. For the Western Interconnection, the ~~,~~ Western Electric Coordinating Council (WECC) performs this work. For the Eastern Interconnection, ~~, and~~the Eastern Interconnection Reliability Assessment Group (ERAG) consisting of MRO, NPCC, RF, and SERC performs this work. The ERAG also performs the base-case model creator function for the Quebec Interconnection in Canada. As the ERO, NERC is responsible for overseeing and ensuring that these designated entities perform the proposed MOD-032-2 Requirement R4 activities. In 2023, the Officers Leadership Team of the ERO Enterprise approved the MOD-032 Designee process document. This process document reflects the maturation of this aspect of the ERO's activities and contains clauses and processes that require the designee for the Interconnection to perform specific duties. Each designee must have certain attributes,

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		including a governance structure responsive to the needs of Planning Coordinators, with clear roles and responsibilities for model creation, transparency in data requirements, establishing timeframes for review cycles, and defining security and access to models. Certain core cases are required as part of this process, including core cases for the ERO for use in seasonal planning studies and event analyses. Other core cases are required for validating Interconnection Frequency Response obligations and event analyses. Lastly, the process requires the development of typical cases to support implementation of the TPL-001 standard. NERC or the Regional Entities may request additional specialized cases as needed. Designated entities have certain responsibilities under this framework, including developing a method for collecting data from all Planning Coordinators and developing and maintaining a case creation manual including the process by which cases must be assembled, tested for quality, and tested for case fidelity according to ERO case quality metrics. NERC will perform an annual case quality assessment, and the designee must address any case model deficiencies identified by NERC. The process also contemplates feedback processes and processes for correcting cases or addressing recurring data or model errors with Planning Coordinators, among other controls, to ensure quality. Regarding the ERAG, there is also an Eastern Interconnection Regional Entity Agreement among MRO, NPCC, RF, and SERC[1]. In this agreement,

[1] EI-Regional-Entity-Agmt-Final-Signed.pdf

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		there are provisions for oversight and coordination in how this group exercises its authority as the MOD-032 designee. ~~important~~ Cconnections to MOD-032 are acknowledged, ~~like the following~~such as: • Oversight of the Multiregional Modeling Working Group[2] (MMWG, whose membership is comprised of one power flow representative and one dynamics representative from each of the Data Submitting Entities (comprised of Planning Coordinators or group of Planning Coordinators) and non-voting representatives as follows: one liaison representative each of the EI Regions and the ERAG Chair, a coordinator from each of the organizations that provides model development services to MMWG, and NERC and FERC staff liaisons. ○ The purpose of the MMWG is to coordinate, in a timely manner, the development of designated power flow and dynamics simulation base case models that realistically simulate steady state and dynamic bulk electric system behavior of the Eastern Interconnection. ○ To ensure cases and models are done in a consistent fashion, the MMWG holds three annual meetings along with conference calls as needed. The MMWG roster includes a FERC liaison who can attend all meetings. The group maintains a case building procedure manual[3] that is used by its members. The manual contains a set of data checks that are performed on the steady state and dynamic cases.

[2] ERAG-MMWG-Charter-2024.pdf

[3] Microsoft Word - ERAG Base Case Release Procedure

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		• Oversight of the Acceptable Model Working Group (AMWG)[4], which is comprised of: (1) Planning Coordinators or group of Planning Coordinators who are responsible for the development and maintenance of an Eastern Interconnection dynamic acceptable model list, and (2) RE and NERC staff who are responsible for coordination and facilitation. ○ The group was formed in 2023 and recently published the first version of its acceptable model list which was posted to the public ERAG website[5]. As models are removed from the acceptable list, the group develops an industry communication to begin removing those models from the annual set of cases. ○ Oversight includes review of all process changes made to the AMWG procedures to ensure consistency with the NERC case quality metrics. ~~• The ERO Enterprise Designation for MOD-032-1: NERC is designating the MOD-032-1 "Designated Entity: responsibilities to the Regional Entities to support NERC in fulfilling its obligations under Requirement R4 given their expertise in their respective geographic jurisdiction."~~ ~~The MOD-032 designees are contractually bound to carry out their duty for building the Interconnection-wide base cases.~~

[4] https://www.rfirst.org/wp-content/uploads/2023/10/ERAG_AcceptableModel_WorkingGroup_Charter.pdf

[5] www.erag.info

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		~~The MOD-032 Designee process document that was approved by the Officers Leadership Team (consisting of upper management of all the ERO Enterprise) contains clauses and processes that require the Designee for the interconnection to perform specific duties. Among those duties are to maintain a governance structure to include all the PCs in their respective Interconnection and, in consultation with all of their respective PCs, to create and make available planning cases. These cases are used in the TPL-001 assessments as outlined in the agreements, which includes a direct PC to PC sharing.~~ In addition, ~~the DT has considered the~~NERC further considered the following information provided by the MOD-032 Designee Group comprised of members from NERC and the Regional Entities: **MOD-032 Designee Group:** The electric grid is evolving at an unprecedented pace, driven by the rapid integration of inverter-based resources (IBRs), changing load characteristics, and emerging technologies. As the system transforms, ~~too must~~ the models we use to study and understand its behavior must also transform. We recognize the growing challenge of obtaining and coordinating accurate dynamic models for IBRs, including securing the appropriate parameters needed to ensure that simulation results reflect real-world system performance. Addressing these modeling challenges is essential to maintaining the reliability and resilience of the bulk power system and requires close collaboration, and the MOD-032 designees along with PCs are committed to and holding data providers accountable for model coordination and model quality. The MOD-032 designees are committed to ensuring that the model quality is maintained and there is a mechanism in place for the PC/TP to

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		gather the appropriate information from the Generator Owners (GO). NERC facilitates the designee group of Regional Entity staff who are responsible for designee activities. ~~This group meets periodically to discuss case quality metrics and to improve the interconnection case-building process. A sub-team has been assembled to write a MOD-032 SAR to add authority for the Designee to enforce model quality.~~ *** In summary, the proposed revisions to the standards addressed in Milestone 3 work, along with the ERO designated entity framework discussed above for building Interconnection-wide cases, address the concerns underlying the Commission's directive in paragraph 161 of Order No. 901 regarding the coordination, updating, and timely development of quality Interconnection-wide models that accurately represent the behavior of IBRs in the Interconnection. Further, this framework advances consistency in modeling used across planning and ERO assessment activities. NERC therefore submits that this framework represents an equally effective and efficient approach to addressing this part of the Commission's paragraph 161 directive to identify a registered modeling designee in the MOD-032 standard. ~~Overall, the FERC directive has been addressed through current and updated requirements/processes.~~
P226. "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	MOD-032 IRO-010 TOP-003	**Theme:** Sufficient timeframe. The DT felt that four years was an appropriate timeframe for the MOD-032, IRO-010, and TOP-003 implementation times. It is understood that based on what is required via MOD-032, industry would need two years to hold meetings with stakeholders to establish processes for collecting the needed models and data, and then an additional two years to update models based on the new requirements, etc. However, taking into consideration the FERC Order 901 implementation deadline of 2030, the

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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 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."		DT settled on a three-year implementation time knowing that milestone 4 revisions still need to be implemented by 2030 and are dependent on the Milestone 3 implementation plan time. Three- year implementation plans were also selected for TOP-003 and IRO-010 to align potential new data requests under TOP-003 and IRO-010 with the expected data availability under MOD-032 processes.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Unacceptable Models List

Project 2022-02 Uniform Modeling Framework for IBR

September 2025

RELIABILITY | RESILIENCE | SECURITY






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Overview/Introduction

FERC issued Order No. 901 on October 23, 2023, directing "NERC to develop new or modified Reliability Standards that require the use of approved industry generic library IBR models that accurately reflect the behavior of IBRs during steady state, short-circuit, and dynamic conditions when developing planning, operations, and interconnection-wide models. For example, the new or modified Reliability Standards could reference the NERC approved component model list, which defines the models that may be used, and those models that may not be used, for specific types of studies. This approved component model list includes WECC's IBR models. Without requiring the use of approved industry generic library models, Bulk-Power System planners and operators may not be able to create system models that adequately predict IBR behaviors and subsequent impacts on the Bulk-Power System."

Proposed Reliability Standard MOD-032-2 addresses the reliability issue identified by FERC in Order No. 901 in a manner that considers advancements in user written models since the issuance of Order No. 901, perspectives of planning entities across North America, and the historical practice of the ERO, which has been to maintain a use of unacceptable models, rather than acceptable models, due to the practical difficulties of keeping an acceptable model library up to date in a timely manner.

Reliability Standard MOD-032-2 requires the Planning Coordinator and Transmission Planner to include specifications addressing the use of standard library models, user-written models meeting certain minimum usability requirements to minimize the risk of non-convergence, or both. To minimize the use of models with known deficiencies, Transmission Planners and Planning Coordinators must also include provisions to require any entity submitted on the Unacceptable Model List to include a technical rationale supporting its use.

The Unacceptable Models List identifies models that are generally considered not acceptable for purposes of model submissions under the MOD-032, TOP-003, and IRO-010 Reliability Standards due to identified issues with usability or accuracy impacting the ability to develop planning or operational horizon cases necessary to support analysis of the reliability of the interconnected transmission system. However, it is recognized that the use of such models may be appropriate in some cases, such as where there is no feasible means for procuring an alternative model that may better represent the behavior of legacy equipment. Any use of such models must include a technical rationale supporting its use.

Disclaimers

Interconnection-wide modeling requirements may differ from the requirements of specialized studies dedicated to a particular technical objective. Thus, models deemed acceptable for planning purposes may be deemed unacceptable by a receiving entity for certain operations applications.

Updates to the Unacceptable Models List

Refer to the Supporting Document section of MOD-032.

Chapter 1: Unacceptable Models List

Models that have been identified as unacceptable are listed in Table 1 below. Revisions to this list may be made in accordance with the process described in the Supporting Document section of the MOD-032 standard.

Table 1: Unacceptable Model List		
Known Unacceptable Model Name	**Model Description**	**Effective**
Renewable Energy Models		
WT3G1, WT3G2, wt3g	Generic Type 3 WTG Generator/Converter Model - Doubly-fed induction generator	Effective Date of MOD-032-2
WT4G1, WT4G2, wt4g	Generic Type 4 WTG Generator/Converter Model - Variable speed generator with full converter	Effective Date of MOD-032-2
WT3E1, wt3e	Generic Type 3 WTG Electrical Control Model	Effective Date of MOD-032-2
WT4E1, WT4E2, wt4e	Generic Type 4 WTG Electrical Control Model	Effective Date of MOD-032-2
WT3T1, wt3t	Generic Type 3 WTG Turbine Model	Effective Date of MOD-032-2
WT3P1, wt3p	Generic Type 3 WTG Pitch Control Model	Effective Date of MOD-032-2
WT12A1, wt1p, wt2p	Generic Type 1 and 2 WTG Pitch Control Model	Effective Date of MOD-032-2
WT4E1, wt4t	Generic Type 4 WTG Power Converter Model	Effective Date of MOD-032-2
wt4p	Generic Type 4 Pitch Control Model	Effective Date of MOD-032-2
REECB1, REECBU1, reec_b	Generic Phase 2 PV Electrical Controls Model	Effective Date of MOD-032-2
Machine Models		
GENSAL, gensal	Salient Pole Generator Model (IEEE Std 1110 §5.3.1 Model 2.1)	Effective Date of MOD-032-2
GENCLS, gencls	Classical Generator Model (IEEE Std 1110 §5.4.2)	Effective Date of MOD-032-2
GENTRA	Transient Level Generator Model	Effective Date of MOD-032-2
Excitation System Models		
texs	General Purpose Transformer Fed Excitation System	Effective Date of MOD-032-2
SEXS, sexs	Simplified Excitation System	Effective Date of MOD-032-2
EX2000	GE EX2000 Excitation System	Effective Date of MOD-032-2
Turbine-Governor Models		
lm2500	LM 2500 Aero-Derivative Gas Turbine Governor Model	Effective Date of MOD-032-2
Known Unacceptable Model Name	**Model Description**	**Effective**

Table 1: Unacceptable Model List		
lm6000	LM 6000 Aero-Derivative Gas Turbine Governor Model	Effective Date of MOD-032-2
URGS3T, gast	WECC Gas Turbine Governor Model	Effective Date of MOD-032-2
GAST	Gas Turbine-Governor Model	Effective Date of MOD-032-2
GAST2A	Gas Turbine-Governor Model	Effective Date of MOD-032-2
GASTWD	Gas turbine-governor	Effective Date of MOD-032-2
IEEEG2	1981 IEEE Type 2 General Approx. Linear Ideal Hydro Model	Effective Date of MOD-032-2
WESGOV	Westinghouse Digital Governor Model for Gas Turbines	Effective Date of MOD-032-2
Load Models		
motorc	Phasor Model of Single-Phase Air-Conditioner Compressor Motor	Effective Date of MOD-032-2

Chapter 2: Unacceptable Models Technical Rationale

Table 2 below provides the technical rationale for each unacceptable model included on the current Unacceptable Models List.

The purpose of this list of unacceptable models is to develop and maintain a repository of models deemed acceptable by the ERO and industry stakeholders for use in developing interconnection-wide models developed by the MOD-032 Designee. The NERC System Analysis and Modeling Subcommittee (SAMS) initially developed this list, and it is now maintained and updated by ERO staff in accordance with MOD-032 Supporting Document. This list seeks to bring together multiple sources of data to ensure uniformity in the use of models across Interconnections. While models may be deemed 'obsolete' or 'deprecated' due to known issues, these models are not removed from the software vendor libraries for various reasons. However, these models should not be used to represent specific facilities within Interconnection-wide models. For additional information about this list, please contact NERC staff at advancedsystemanalyticsmodeling@nerc.net with any questions.

Table 2: Unacceptable Model List

Known Unacceptable Model Name	Rationale For Inclusion
Renewable Energy Models	
WT3G1, WT3G2, wt3g	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT4G1, WT4G2, wt4g	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3E1, wt3e	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT4E1, WT4E2, wt4e	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3T1, wt3t	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT3P1, wt3p	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
WT12A1, wt1p, wt2p	Unable to represent common Type 1 wind pitch control logic.
WT4E1, wt4t	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
wt4p	Replaced by 2nd Generation renewable models. 1st Generation generic models have produced numerical instability for on-fault conditions for power electronics represented by this model
REECB1, REECBU1, reec_b	Inability to represent momentary cessation or other voltage dependent current logic common in the equipment the model was stated to represent.
Machine Models	

Table 2: Unacceptable Model List	
Known Unacceptable Model Name	**Rationale For Inclusion**
GENSAL, gensal	Uses simplifying approximations for saturation as additive terms over exponential or quadratic curves. Further, ignores the q-axis saturation completely.
GENCLS, gencls	Does not allow for representation of excitation system and turbine/speed governor models
GENTRA	Simplified model that ignores sub transient effects, leading to numerical instability problems.
Excitation System Models	
texs	Simplified, early generation model considered obsolete. Refer to IEEE Std 421.5
SEXS, sexs	Simplified, early generation model considered obsolete. Refer to IEEE Std 421.5
EX2000	Field current limiter latch in the model is unable to represent the field equipment for simulation in power system software. Replace with AC7B or ex21br
Turbine-Governor Models	
lm2500	No supporting documentation implemented in software, proprietary model with no added model support.
lm6000	No supporting documentation implemented in software, proprietary model with no added model support.
URGS3T, gast	Simple representation of steam turbine-governor system with insufficient model capability for modern digital controllers.
GAST	Simple representation of steam turbine-governor system with insufficient model capability for modern digital controllers.
GAST2A	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
GASTWD	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
IEEEG2	Model uses an oversimplified governor model applicable only to first swing stability. Deprecated with other hydro governor models.
WESGOV	Simple representation of steam turbine-governor system with insufficient model capability and flexibility for modern digital controllers.
Load Models	
motorc	Experimental load model. Should not be used for generation resources

Additional References

The references below are provided for further reading and information about the models above. These references are:

- "IEEE Guide for Synchronous Generator Modeling Practices and Applications in Power System Stability Analyses," IEEE Std 1110-2002.
- Undrill, J., "The gentpj model," November 19, 2007 (updated June 19, 2012).
- "IEEE Recommended Practice for Excitation System Models for Power System Stability Studies," IEEE Std 421.5-2005.
- "Computer Representation of Excitation Systems," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-87, No. 6, pp. 1460-1468, 1968 (Committee Report).
- "Excitation System Models for Power System Stability Studies," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 2, pp. 494-509, 1981 (Committee Report).

- IEEE Task Force on Overall Plant Response, "Dynamic Models for Steam and Hydro Turbines in Power System Studies", IEEE Trans. on PAS, Vol PAS-92, Nov-Dec 1973, pp. 1904-1915.
- Task Force on Turbine-Governor Modeling, "Dynamic Models for Turbine-Governors in Power System Studies," IEEE Technical Report, PES-TR1, Jan. 2013.
- WECC M&VWG, "Composite Load Model for Dynamic Simulations" Ver 1.0, June 12, 2012.
- WECC M&VWG, "WECC Wind Power Plant Dynamic Modeling Guide," November 2010.
- EPRI, "Specification of the Second Generation Generic Models for Wind Turbine Generators," September 20, 2013. and WECC M&VWG, "Generic Solar Photovoltaic System Dynamic Simulation Model Specification," September 2012.
- WECC, "Generic Static Var System Models for the Western Electricity Coordinating Council" April 18, 2011.
- W. I. Rowen, "Simplified Mathematical Representations of Heavy Duty Gas Turbines", ASME Paper 83-GT-63 and ASME Journal of Engineering for Power, October 1983, pages 865-869. [GAST2A reference]
- Periera, L. et al, "A New Thermal Governing Approach in the WECC," IEEE Transaction on Power System, Vol. 18, No. 2, pp. 819-829, May 2003.
- WECC M&VWG, "Cross-current Compensation Model Specification," August 2015.
- EPRI, "Simple Model Specification for Battery Energy Storage System," March 6, 2015.
- WECC M&VWG, "WECC Wind Power Plant Dynamic Modeling Guide," April 2014.
- WECC M&VWG, "WECC PV Power Plant Dynamic Modeling Guide," April 2014.
- EPRI, "Proposed Changes to the WECC WT3 Generic Model for Type 3 Wind Turbine Generators," September 27, 2013.
- EPRI, "Proposed Changes to the WECC WT4 Generic Model for Type 4 Wind Turbine Generators," January 23, 2013.
- Q. Wang, "GENQEC Generator Dynamic Model", July, 2019. https://www.wecc.org/Administrative/GENQEC%20Model%20Specification.pdf
- Q.Y. Wang, S. Wang, "A New High Accuracy Generator Dynamic Model", 2018 IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC).

Chapter 3: Sample Submission Form

This form is a sample to explain what is deemed a full application to change a model designation in the Unacceptable Models List.

Section 1: Submitting Entity Information			
Name of Person submitting			
Organization(s)			
Sector (if known)			
Telephone		Email	

Section 2: Model Identifying Information	
Model Name	
Alternative Model Name(s) as implemented in software	
Equipment Model is stated to represent	
Indicate desired Action	☐ Add model to the Unacceptable Models List ☐ Remove model from the Unacceptable Models List

Section 3: Technical Supporting Documentation and Description	
Description of model ability to meet small signal Disturbances	
Description of model ability to meet large signal Disturbances	
Please cite and link any industry approved documentation regarding this model's small and large signal disturbances	
Describe the technical document attachments that support the above questions	
Please identify any information in this application that may meet the criteria for Confidential Information, as defined in Section 1500 of the NERC Rules of Procedure	

Section 4: Process Tracking	
Date Submitted to ERO	
Model Status	☐ Submitted to the ERO ☐ Assigned ERO Review team ☐ Investigation and review by ERO and submitting entity ☐ Remanded by NERC RSTC (or its successor) ☐ Approved by the NERC RSTC (or its successor)
Date of Approval	
Date of Model Notice to Industry	

Attachments

If available, please include at least one report that uses Hardware-in-the-Loop, Software-in-the-Loop, or actual System response (e.g., in a commissioning test) to demonstrate the model's ability or inability to achieve its stated purpose. At least one attachment should detail the model's error boundaries to represent its stated equipment with the test description and procedure outlined in that report. Entities shall label any attachment that may meet the criteria for Confidential Information under NERC Rules of Procedure Section 1500, along with the basis for the designation (e.g., Confidential Business and Market Information, Critical Electric Infrastructure Information, etc.). If any of this information is not available to the supporting entity, please provide an explanation.

Chapter 4: Version History

Version	Date	Action	Change Tracking
1	August 2025	Draft 2 Posting for Project 2022-02	Initial Draft

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-02 Uniform Modeling Framework for IBR

Final Ballots Open through October 3, 2025

Now Available

Final ballots for **Project 2022-02 Uniform Modeling Framework for IBR** are open through **8 p.m. Eastern, Friday, October 3, 2025** for the following standards and implementation plan:

- MOD-032-2 – Data for Power System Modeling and Analysis
- IRO-010-6 – Reliability Coordinator Data and information Specification and Collection
- TOP-003-8 – Transmission Operator and Balancing Authority Data and Information Specification and Collection
- Implementation Plan

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

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

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 470-479-7538.



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

Ballot Results

Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 MOD-032-2 FN 3 ST
Voting Start Date: 9/29/2025 10:06:45 AM
Voting End Date: 10/3/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 261
Total Ballot Pool: 280
Quorum: 93.21
Quorum Established Date: 9/29/2025 2:20:10 PM
Weighted Segment Value: 78.73

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	48	0.738	17	0.262	0	7	0
Segment: 2	7	0.6	6	0.6	0	0	0	0	1
Segment: 3	66	1	45	0.776	13	0.224	0	2	6
Segment: 4	14	1	10	0.769	3	0.231	0	0	1
Segment: 5	68	1	39	0.736	14	0.264	0	7	8
Segment: 6	47	1	32	0.762	10	0.238	0	2	3
Segment: 7	0	0	0	0	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:	280	6.2	185	4.881	58	1.319	0	18	19

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Negative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	N/A

5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	N/A
3	AES - Indianapolis Power and Light Co.	Sam Hake		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		Negative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Negative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ken Bartz		Negative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Negative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	N/A
3	Omaha Public Power District	David Heins		Negative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A

1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	N/A
6	Salt River Project	Israel Perez	Timothy Singh	Negative	N/A
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Negative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	N/A
1	Salt River Project	Laura Somak	Timothy Singh	Negative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Negative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A

6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
6	Entergy	Julie Hall		Negative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
5	Orsted Americas	Keith Smith		None	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Negative	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
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
6	AEP	Randy Calhoun		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Negative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A

6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Negative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Platte River Power Authority	Jim Grothmann		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Negative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A

3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Negative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	N/A
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Negative	N/A
6	Cleco Corporation	Robert Hirchak		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey	Danielle Moskop	Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	N/A
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A

[redacted]

Ballot Results

Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 IRO-010-6 FN 3 ST
Voting Start Date: 9/29/2025 10:06:56 AM
Voting End Date: 10/3/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 260
Total Ballot Pool: 281
Quorum: 92.53
Quorum Established Date: 9/29/2025 2:20:40 PM
Weighted Segment Value: 87.78

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	73	1	57	0.905	6	0.095	0	8	2
Segment: 2	7	0.6	2	0.2	4	0.4	0	0	1
Segment: 3	66	1	54	0.931	4	0.069	0	2	6
Segment: 4	14	1	13	1	0	0	0	0	1
Segment: 5	68	1	46	0.902	5	0.098	0	9	8
Segment: 6	47	1	38	0.905	4	0.095	0	2	3
Segment: 7	0	0	0	0	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:	281	6.2	216	5.443	23	0.757	0	21	21

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A

3	AES - Indianapolis Power and Light Co.	Sam Hake		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ken Bartz		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Negative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A

5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	N/A
6	Salt River Project	Israel Perez	Timothy Singh	Negative	N/A
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	N/A
1	Salt River Project	Laura Somak	Timothy Singh	Negative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A

6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Orsted Americas	Keith Smith		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		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
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
6	AEP	Randy Calhoun		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A

6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Platte River Power Authority	Jim Grothmann		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A

3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey	Danielle Moskop	Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	N/A
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A

Ballot Results

Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 TOP-003-8 FN 3 ST
Voting Start Date: 9/29/2025 10:07:07 AM
Voting End Date: 10/3/2025 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 261
Total Ballot Pool: 281
Quorum: 92.88
Quorum Established Date: 9/29/2025 2:20:58 PM
Weighted Segment Value: 84.3

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	73	1	56	0.889	7	0.111	0	9	1
Segment: 2	7	0.6	2	0.2	4	0.4	0	0	1
Segment: 3	66	1	51	0.895	6	0.105	0	3	6
Segment: 4	14	1	12	0.923	1	0.077	0	0	1
Segment: 5	68	1	44	0.863	7	0.137	0	9	8
Segment: 6	47	1	36	0.857	6	0.143	0	2	3
Segment: 7	0	0	0	0	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:	281	6.2	207	5.227	31	0.973	0	23	20

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Negative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	N/A
3	AEP	Jodi Yeary		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A

3	AES - Indianapolis Power and Light Co.	Sam Hake		None	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ken Bartz		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Negative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A

5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	N/A
6	Salt River Project	Israel Perez	Timothy Singh	Negative	N/A
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	N/A
1	Salt River Project	Laura Somak	Timothy Singh	Negative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A

6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
5	Orsted Americas	Keith Smith		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		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
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
6	AEP	Randy Calhoun		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A

6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
5	Seattle City Light	Chris Shultz		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Platte River Power Authority	Jim Grothmann		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A

3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	N/A
1	Lincoln Electric System	Josh Johnson		Negative	N/A
3	Lincoln Electric System	Sam Christensen		Negative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	N/A
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3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
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5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
3	TXNM Energy	Scott Thompson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	N/A
1	Ameren - Ameren Services	Tamara Evey	Danielle Moskop	Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Abstain	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A

Ballot Results

Ballot Name: 2022-02 Uniform Modeling Framework for IBR | Draft 1 Implementation Plan FN 3 OT
Voting Start Date: 9/29/2025 10:07:20 AM
Voting End Date: 10/3/2025 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 255
Total Ballot Pool: 275
Quorum: 92.73
Quorum Established Date: 9/29/2025 11:45:53 AM
Weighted Segment Value: 79.39

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	73	1	52	0.8	13	0.2	0	7	1
Segment: 2	7	0.5	2	0.2	3	0.3	0	1	1
Segment: 3	64	1	47	0.855	8	0.145	0	3	6
Segment: 4	13	1	10	0.833	2	0.167	0	0	1
Segment: 5	67	1	37	0.771	11	0.229	0	10	9
Segment: 6	45	1	33	0.805	8	0.195	0	2	2
Segment: 7	0	0	0	0	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	1	0
Totals:	275	6	186	4.764	45	1.236	0	24	20

Ballot Pool Members

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips		Negative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
3	Tri-State G and T Association, Inc.	Amanda Skubal		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
1	TXNM Energy	Lynn Goldstein		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Lower Colorado River Authority	Joseph Scott		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Alain Mukama	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		Abstain	N/A
5	American Municipal Power	Amy Ritts		Abstain	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	AEP	Jodi Yeary		Negative	N/A
3	WEC Energy Group, Inc.	Christine Kane		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A

5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Sam Hake		None	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Amy Key		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
1	Black Hills Corporation	Trevor Rombough		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
5	Grid Strategies LLC	Michael Goggin		Abstain	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		Negative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Ken Bartz		Negative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Balancing Authority of Northern California	Kris Kirkegaard	Tim Kelley	Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Ray Mangiulli		Negative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Negative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		None	N/A
6	Omaha Public Power District	Shonda McCain		Negative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A

1	Glencoe Light and Power Commission	Terry Volkmann		Negative	N/A
5	Leeward Renewable Energy	Rob Robertson		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
6	Northern California Power Agency	Benjamin Hector		None	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	None	N/A
5	WEC Energy Group, Inc.	Catherine Doyle		None	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	N/A
6	Salt River Project	Israel Perez	Timothy Singh	Negative	N/A
3	Tennessee Valley Authority	Justin Kuhlers		None	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	N/A
2	ISO New England, Inc.	John Pearson		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
3	Salt River Project	Mathew Weber	Timothy Singh	Negative	N/A
1	Salt River Project	Laura Somak	Timothy Singh	Negative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley	Adrian Harris	Negative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
4	Western Power Pool	Kevin Conway		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr	Nick Leathers	Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Affirmative	N/A
5	Constellation	Marie Potter		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
3	Dominion - Dominion Virginia Power	Matt Bullard		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Barbara Marion		Affirmative	N/A
5	DTE Energy	George Goddard		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A

6	Dominion - Dominion Resources, Inc.	Alex Bekashoff		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		Abstain	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
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
5	Orsted Americas	Keith Smith		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		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
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A
6	Western Area Power Administration	Jennifer Neville		Negative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	N/A
6	AEP	Randy Calhoun		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	Central Iowa Power Cooperative	Kelly Heims		Affirmative	N/A
6	Xcel Energy, Inc.	Patrick Flaherty		Affirmative	N/A
1	National Grid USA	Jacqueline Ryan		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A

6	Duke Energy	John Sturgeon		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	David Melanson		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	EDF Renewable Energy	Steven Sconce		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
2	Independent Electricity System Operator	Pirouz Honarmand		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
5	Platte River Power Authority	Jim Grothmann		None	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Robert Witham		Affirmative	N/A
10	Northeast Power Coordinating Council	Ruida Shu		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Negative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A

3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
3	JEA	Marilyn Williams		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Negative	N/A
1	Lincoln Electric System	Josh Johnson		Negative	N/A
3	Lincoln Electric System	Sam Christensen		Negative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Affirmative	N/A
5	Salt River Project	Matthew Jaramilla	Timothy Singh	Negative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Breen		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez	Linda Henrickson	Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		None	N/A
5	Muscatine Power and Water	Chance Back		Negative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A

6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey	Danielle Moskop	Affirmative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Wickel		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
5	BC Hydro and Power Authority	Vijay Raghunathan		Abstain	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
5	Basin Electric Power Cooperative	Amanda Wangler		Negative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Affirmative	N/A
6	Basin Electric Power Cooperative	Eve G Stromer		Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Negative	N/A
1	Oncor Electric Delivery	Byron Booker	Karina Valencia	Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
6	Constellation	Laura Brignola		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
6	NiSource - Northern Indiana Public Service Co.	Eugene Johnson		Negative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit I

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Drafting Team (DT) Roster

Project 2022-02 Uniform Modeling Framework for IBR

	Name	Entity
Chair	John Schmall	Electric Reliability Council of Texas, Inc.
Vice Chair	Jonathan Hayes	Southwest Power Pool
Members	Josie Daggett	Western Area Power Administration
	Hassan Baklou	SDG&E
	Qiushi (Cho) Wang	The AES Corporation
	Patrick Dalton	Midcontinent Independent System Operator (MISO)
	Alexander Stewart	Bonneville Power Administration
	Joshua Pierce	Southern Company Services
	Mohit Singh	Exelon
	Andrea Pinceti	Dominion Energy
	Hayden Maples	Evergy
	Ejovi Ovhori	Duke Energy Carolinas
	Steve Wendling	American Transmission Company, LLC
PMOS Liaison	Donnovan Crane	WECC
NERC Staff	Jordan Mallory – Senior Standards Developer	North American Electric Reliability Corporation
	Lauren Perotti – Legal	North American Electric Reliability Corporation
	John (JP) Skeath – Senior Engineer	North American Electric Reliability Corporation