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~~~~P~~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 ~~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.