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 35-day comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	May 15, 2024
SAR posted for comment	May 23 – June 28, 2024

Anticipated Actions	Date
35-day formal comment period with 10-day ballot	April 17 – May 21, 2025
20-day formal or informal 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):

The terms Model Validation and Distributed Energy Resources refer to proposed definitions being developed by Project 2020-06 Verifications of Models and Data for Generators and Project 2022-02 Uniform Framework for IBR, respectively. As of this posting, the proposed definitions of Model Validation and Distributed Energy Resources are:

Model Validation: The process of comparing measurements with simulation results to assess how closely a model's behavior matches the measured behavior.

Distributed Energy Resources: 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:** **Steady-State and Dynamic System Model Validation**

2. **Number:** **MOD-033-~~2~~3**

3. **Purpose:** To establish ~~consistent~~a comprehensive process for system model validation ~~requirements~~ to facilitate ~~the collection of accurate data~~achieving and ~~building of planning models to analyze the reliability of the interconnected transmission system~~maintaining adequate model accuracy.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Reliability Coordinator

   4.1.3. Transmission Operator

Effective Date: See Implementation Plan for MOD-033-3

B. Requirements and Measures

R1. Each Planning Coordinator shall implement a documented ~~data validation~~Model Validation process for its portion of the existing system that includes the following attributes: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Comparison of the power flow simulation performance of the ~~Planning Coordinator's portion of the existing system in a planning power flow~~ steady state System model[1] to actual ~~s~~System behavior, represented by ~~a~~ state estimator case(s) or other Real-time data sources, at least once every 24 calendar months ~~through simulation;~~ ;

1.2. Comparison of the dynamic local event simulation performance of the ~~Planning Coordinator's portion of the existing system in a planning dynamic~~dynamic System model to actual ~~system response, through simulation of a dynamic local event,~~System behavior, represented by Real-time data sources such as Disturbance data recording(s), at least once every 24 calendar months (us~~e~~ing a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison~~,~~[2]) and complet~~e~~ing each comparison within 24 calendar months of the dynamic local event.~~). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;~~.

1.3. Guidelines ~~the Planning Coordinator will use~~ to determine unacceptable differences in performance under Parts 1.1 ~~or~~and 1.2; and

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. ~~Each Planning Coordinator shall provide~~Acceptable evidence ~~that it has~~may include, but is not limited to, a copy of the documented ~~validation~~Model Validation process ~~according to Requirement R1 as well as evidence~~and documentation that demonstrates ~~the~~its implementation ~~of the required components of the process~~in accordance with Requirement R1.

R2. Each Reliability Coordinator and Transmission Operator shall, within 30 calendar days of a written request, provide actual ~~s~~System behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing ~~validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation.~~Model

[1] System models include unregistered Inverter-Based Resources (IBRs) and aggregate Distributed Energy Resources (DERs) when present. 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.

[2] If no dynamic local event occurs within this 24 calendar months period, use the next dynamic local event that occurs.

Validation under Requirement R1. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~**M2.** Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.~~

M2. Acceptable evidence may include, but is not limited to, a copy of the dated communication(s) in accordance with Requirement R2.

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 ~~through~~ and R2, ~~and Measures M1 through M2,~~ 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:~~**

~~1.4.~~**1.3.** ~~Refer to Section 3.0 of Appendix 4C of~~ **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 ~~for~~) or the Commission-approved program of a ~~list of~~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 ~~assessment processes~~enforcement activities with respect to Registered Entities' compliance with Reliability Standards.

~~**1.5. 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~~	~~Medium~~	The Planning Coordinator ~~documented and~~ implemented a documented Model Validation process ~~to validate data~~ but ~~did not~~failed to address one of the four ~~required topics under~~ attributes stipulated in Requirement R1~~;~~, Parts 1.1 through 1.4. OR The Planning Coordinator ~~did not perform simulation~~performed the comparison as ~~required~~stipulated in Parts 1.1 or 1.2 but was late by ~~part 1.1 within 24~~less than or equal to 4 calendar	The Planning Coordinator ~~documented and~~ implemented a documented Model Validation process ~~to validate data~~ but ~~did not~~failed to address two of the four ~~required topics under~~ attributes stipulated in Requirement R1~~;~~, Parts 1.1 through 1.4. OR The Planning Coordinator ~~did not perform simulation~~performed the comparison as ~~required by part 1.1 within 24 calendar months~~ stipulated in Parts 1.1 or 1.2 but ~~did perform the~~	The Planning Coordinator ~~documented and~~ implemented a documented Model Validation process ~~to validate data~~ but ~~did not~~failed to address three of the four ~~required topics under~~ attributes stipulated in Requirement R1~~;~~, Parts 1.1 through 1.4. OR The Planning Coordinator ~~did not perform simulation~~performed the comparison as ~~required by part 1.1 within 24 calendar months~~ stipulated in Parts 1.1 or 1.2 but ~~did perform the~~	The Planning Coordinator ~~did not~~failed to have a ~~validation~~documented Model Validation process ~~at all or did not document or implement any of the four required topics under~~in accordance with Requirement R1~~;~~. OR The Planning Coordinator ~~did not validate~~ failed to implement its ~~portion of the system in the power flow model as required by part 1.1 within 36 calendar months;~~documented Model Validation process in accordance with Requirement R1. OR

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			months~~ but did perform the simulation within 28 calendar months;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.~~ .	~~simulation in greater~~was late by more than ~~28~~4 calendar months but less than or equal to ~~32~~8 calendar months~~;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.~~ .	~~simulation in greater~~was late by more than ~~32~~8 calendar months but less than or equal to ~~36 calendar months;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36~~12 calendar months.	The Planning Coordinator ~~did not perform simulation as required by part~~ performed the comparison as stipulated in Parts 1.1 or 1.2 ~~within 36 calendar months (or the next dynamic local event in cases where there is~~ but was late by more than ~~24~~12 calendar months ~~between events).~~.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2.	~~Long-term Planning~~	~~Lower~~	The Reliability Coordinator or Transmission Operator ~~did not provide~~provided the requested ~~actual system~~System behavior data ~~(~~or ~~a~~ written response that it does not have the requested data~~)~~ to a requesting Planning Coordinator ~~within 30 calendar days of the written request,~~in accordance with Requirement R2 but ~~did provide the data (or written response that it does not have the requested data) in~~ was late by less than or equal to ~~45~~15 calendar days.	The Reliability Coordinator or Transmission Operator ~~did not provide~~provided the requested ~~actual system~~System behavior data ~~(~~or ~~a~~ written response that it does not have the requested data~~)~~ to a requesting Planning Coordinator ~~within 30 calendar days of the written request,~~in accordance with Requirement R2 but ~~did provide the data (or written response that it does not have the requested data) in greater~~was late by more than ~~45~~15 calendar days but less than or equal to ~~60~~30 calendar days.	The Reliability Coordinator or Transmission Operator ~~did not provide~~provided the requested ~~actual system~~System behavior data ~~(~~or ~~a~~ written response that it does not have the requested data~~)~~ to a requesting Planning Coordinator ~~within~~ in accordance with Requirement R2 but was late by more than 30 calendar days ~~of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days~~ but less than or equal to ~~75~~45 calendar days.	The Reliability Coordinator or Transmission Operator ~~did not provide~~provided the requested ~~actual system~~System behavior data ~~(~~or ~~a~~ written response that it does not have the requested data~~)~~ to a requesting Planning Coordinator ~~within 75~~but was late by more than 45 calendar days~~;~~. OR The Reliability Coordinator or Transmission Operator ~~provided a~~failed to provide the requested System behavior data or written response that it does not have the requested data~~, but actually had the data.~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						to a requesting Planning Coordinator.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

E. Associated Documents

- MOD-033-3 Implementation Plan
- MOD-033-3 Technical Rationale

~~**None.**~~

~~**Guidelines and Technical Basis**~~

~~**Requirement R1:**~~

~~**The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see "Procedures for Validation of Powerflow and Dynamics Cases" produced by the NERC Model Working Group.**~~

~~**The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.**~~

~~**For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies "once every 24 calendar months," entities are encouraged to perform the comparison on a more frequent basis.**~~

~~**In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:**~~

1. ~~**System load;**~~
2. ~~**Transmission topology and parameters;**~~
3. ~~**Voltage at major buses; and**~~
4. ~~**Flows on major transmission elements.**~~

~~**The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.**~~

~~**The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator's planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.**~~

~~**The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:**~~

- ~~**Voltage oscillations at major buses**~~
- ~~**System frequency (for events with frequency excursions)**~~
- ~~**Real and reactive power oscillations on generating units and major inter-area ties**~~

~~Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of "at least once every 24 calendar months" is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.~~

~~In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a "month 23" dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event's occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event's occurrence to complete the comparison.~~

~~Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator's system.~~

~~The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this~~

~~standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.~~

~~While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.~~

~~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:~~

~~In FERC Order No. 693, paragraph 1210, the Commission directed inclusion of "a requirement that the models be validated against actual system responses." Furthermore, the Commission directs in paragraph 1211, "that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.~~

~~Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:~~

~~A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and~~

~~B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.~~

~~Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.~~

~~Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.~~

~~Rationale for R2:~~

~~The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.~~

~~This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.~~

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.
1	May 1, 2014	FERC Order issued approving MOD-033-1.	
2	February 6, 2020	Adopted by the NERC Board of Trustees.	Revisions under Project 2017-07

2	October 30, 2020	FERC Order approving MOD- 033-2. Docket No. RD20-4-000	
2	April 1, 2021	Effective Date	
3	TBD	Adopted by the NERC Board of Trustees.	FERC Order No. 901 Revisions by Project 2021-01