Technical Rationale for Reliability Standard

Project 2020-06 Verifications of Models and Data for Generators
MOD-026-2 – Verification of Models and Data | August 2025

Introduction

This document is the technical rationale and justification for Reliability Standard MOD-026-2 and includes the rationale for changes in the current proposed version, as well as previous versions of the standard.

It is intended to provide stakeholders and the ERO Enterprise with an understanding of the revisions, technology and technical concepts of Reliability Standard MOD-026-2. This is not a Reliability Standard and should not be considered mandatory or enforceable.

This project was given directives as part of Milestone 3 Order No. 901. The team used the original work of the MOD-026-2 iterations as a starting part point to help fulfill the directive to fully perform Model Verification and Model Validation registered IBRs. The team developed three NERC Glossary of Terms definitions out of this project: IBR, Model Verification, and Model Validation.

Background

The NERC Inverter-Based Resource (IBR) Performance Task Force (IRPTF) performed a comprehensive review of all NERC Reliability Standards to identify any potential gaps and/or improvements. The IRPTF discovered several issues as part of this effort and documented its findings and recommendations in the *IRPTF Review of NERC Reliability Standards White Paper*, which was approved in March 2020 by the Operating Committee and the Planning Committee (PC) now part of the Reliability and Security Technical Committee (RSTC). Among the findings noted in the white paper, the IRPTF identified issues with MOD-026-1 and MOD-027-1 that should be addressed. The RSTC endorsed the standard authorization request (SAR) on June 10, 2020.

Consistent with the IRPTF recommendations, the scope of the proposed SAR includes revisions to NERC Reliability Standards MOD-026-1 and MOD-027-1. These standards require, among other things, Generator Owners to provide verified dynamic models to their Transmission Planner for the purposes of power system planning studies. The project proposed revisions to MOD-026-1 and MOD-027-1 to clarify requirements related to IBRs, and to require sufficient model verification to ensure accurate generator representation in dynamic simulations. The IRPTF recommended revisions to clarify the applicable requirements for synchronous generators and IBRs.

Additionally, the potential risk of increasing amounts of reactive power being supplied by non-synchronous sources was identified in *NERC's 2017 Long-term Reliability Assessment*. In response to the concern, the PC assigned the System Analysis and Modeling Subcommittee (SAMS) to study the issue. SAMS developed the *Applicability of Transmission-Connected Reactive Devices White Paper*, which was approved by the PC at its December 2019 meeting. The PC Executive Committee approved the SAR on February 11, 2020. Recommended revisions to MOD-026-1 and MOD-027-1 outlined in the SAR were undertaken within the scope of this project. The original SAR and drafting team (DT) took on the task of combining MOD-026-1 and MOD-027-1 into a single standard. This consolidation combined these to standards while also updating language to create MOD-026-2.

Rationale for Applicability Section - Functional Entities

The purpose of the MOD-026-2 standard is to ensure models used in planning and interconnection analyses are verified and validated, and that these models accurately represent in-service equipment. There are four functional entities that play a role in MOD-026-2 requirements and have an obligation to comply with them. These are:

- Generator Owner
- Transmission Owner
- Planning Coordinator
- Transmission Planner

The Generator Owner and Transmission Owner are responsible for providing validated and verified models to the Transmission Planner that reflect in-service equipment and power plant performance. These validated and verified models must reflect the dynamic performance of equipment being installed or already installed in the grid under various expected grid conditions and disturbances, so that Transmission Planners may assess the impact of power plants and transmission-connected devices on grid stability and resiliency.

The Transmission Planner and its Planning Coordinator are responsible for jointly developing and maintaining model requirements for the purpose of Model Verification and Model Validation, and for making them available to the Generator Owner or Transmission Owner.

The Transmission Planner is also responsible for reviewing submitted verified models and accompanying information, updated verified models, and written responses from Generator Owners and Transmission Owners. Transmission Planners are responsible for communicating model acceptance and denial to the Generator Owner or Transmission Owner.

The definition of the term Generator Owner is under revision in Project 2024-01 Rules of Procedure Definitions Alignment (Generator Owner and Generator Operator) and is being proposed for adoption by the NERC Board of Trustees at its August 2025 meeting. Following Board adoption and approval by the applicable governmental authorities, the term Generator Owner will refer to “The entity that: 1) owns and maintains generating Facility(ies) (Category 1 GO); or 2) owns and maintains 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 (Category 2 GO).”

Facilities Section

A facility that would need to meet the requirements in this standard and be considered an "applicable facility" falls under the characteristics defined by the NERC Bulk Electric System (BES) Definition Inclusion I2 and I4 for generating facilities, Inclusion I5 for dynamic reactive resources (synchronous condenser and FACTS devices), or is a high voltage direct current (HVDC) facility. Any unit, plant, or resource connected to the BES and meeting the unit rating criteria set by the BES definition is applicable. This Facilities applicability is consistent with most other NERC reliability standards being tied to BES-qualified units. The proposed standard links applicability to the BES definition (as opposed to defined rating or other thresholds) to be sure that now and in the future, should the BES definition be modified, the standard is consistent with applicable BES facilities. This avoids the need to modify the standard if definitive thresholds are specified and the BES definition is modified.

The DT added language in the Facilities section numbers 4.2.5 and 4.2.6 which cover IBRs that are registered and unregistered devices. These items are carried over from FERC Order No. 901 Milestone 2 projects which ensure these standards not only apply to the BES but also the Bulk Power System (BPS).

Rationale for Requirement R1

Requirement R1 requires the Transmission Planner (TP) and its associated Planning Coordinator (PC) to jointly develop dynamic model requirements necessary for performing Model Verification and Model Validation and make them readily available to Generator Owners (GO) and Transmission Owners (TO) within their area. TPs and PCs need to work on this together in order to ensure that both entities can use the verified models in their studies. This need has been highlighted in NERC disturbance reports.

Part 1.1

MOD-026-2 Requirement R1, Part 1.1 expands MOD-026-1 Requirement R1, bullet 1 to not only require the Transmission Planner to list the acceptable models, but also requires the Transmission Planner to specify the required format and level of detail. The 90-day response time in MOD-026-1 Requirement R1 is removed and instead MOD-026-2 Requirement R1 requires a document to be maintained for distribution. The DT decided not to include a reference to MOD-032 in Requirement R1, Part 1.1. MOD-026-2 establishes the applicable equipment to be modeled in Attachment 1 providing direction for both model verification and model validation. Consequently, the team members believe that a fully validated model, as an output of MOD-026-2, should feed into MOD-032, given MOD-026's more comprehensive nature. The intent of Part 1.1 is to require the Transmission Planner to specify the type of positive sequence models compatible with their planning process. The Transmission Planner should specify the software tools and version numbers that the model must be compatible with and describe the format and submission requirements. The Transmission Planner must specify which models are acceptable and may decide to adopt the NERC Unacceptable Models List. Regarding format, the Transmission Planner may specify compatible file types, may request completion of forms or templates, and may require example cases where the model is set up to run. The Transmission Planner should consider requiring complete documentation / user manuals describing other required model parameters, control block topology, tuning, etc. For other model required parameters, it is common to describe the appropriate apparent power (MVA) base, equivalent reactance (Rsource and Xsource), reactive limits (Qmin and Qmax), and impedances of any generator step-up transformers not explicitly modeled in Powerflow cases. In addition, the Transmission Planner may have requirements to ensure model compatibility, accuracy, or performance and may have specific policies regarding user-defined models versus standard library or generic models.

MOD-026-2 Requirement R1, Part 1.1 requires the Transmission Planner and its associated PC to document positive sequence dynamic model requirements. Examples of such requirements include the following:

1. The type of positive sequence models compatible with their planning process.
2. The software tools and version numbers that the model must be compatible with.
3. Which models are acceptable in view of the NERC Unacceptable Models List.
4. The compatible file types and formatting, the completion of forms or templates, and example cases where the model may be easily run and tested.
5. Model documentation or user manual describing required model parameters, control block topology, parameter tuning, etc.
6. Requirements to ensure model compatibility, accuracy, or performance, and specific policies regarding user-defined models versus standard library or generic models.
7. In Requirement R1, Part 1.1.1, the TP may specify and request that certain synchronous generation limiting and protection models among those listed in Attachment 1, Table 1.1 are verified under Requirement R2.

Part 1.2

MOD-026-2 Requirement R1, Part 1.2 expands requirements of MOD-026-1 Requirement R1, bullet 1 to cover electro-magnetic transient (EMT) models in addition to positive sequence dynamic models. EMT models are not required of all types of generators or devices; only IBRs, FACTS, and HVDC. This Part refers to EMT modeling requirements, which the DT defines as those developed by the Transmission Planner and its Planning Coordinator to ensure consistent EMT models are provided based on the types of studies being performed and the specific EMT simulation tools being used. The applicable Facilities listed in MOD-026-2 Requirement R3 and the exception to Requirement R3 regarding legacy facilities limit the facilities for which verified EMT models need to be submitted by a Generator Owner or Transmission Owner. Requirement R1, Part 1.2 requires the Transmission Planner to document acceptable models, format, and level of detail for generation facilities where EMT models are required. The intent of Part 1.2 is to require the Transmission Planner to specify the type of EMT models compatible with their planning process. The Transmission Planner should specify the type of software used and version (including compiler version). To ensure the model is compatible with nearby models for larger studies, the Transmission Planner may define the range of simulation time-step sizes the model must be capable of operating over. Regarding the level of detail, the Transmission Planner may require full detailed modeling of phase-locked-loops (PLL) and fast current controls, power electronic switches or equivalent switching models (as opposed to average source models). For accuracy, the Transmission Planner may require usage of actual code or require hardware validations/benchmarks or may prohibit models from using certain off-the-shelf library blocks (such as using a generic phase-locked-loop (PLL) control block rather than modeling the actual PLL control block). It is recommended that the Transmission Planner describes the planned use for the EMT model (such as weak-grid studies, sub-synchronous resonance, unbalanced faults, or special islanding or over-voltage protection studies), so that the vendor can ensure an appropriate level of detail. The Transmission Planner should also indicate if balance-of-plant equipment should also be included in the model, including the Power Plant Controller (PPC). For ease-of-use, the Transmission Planner may require certain controls or outputs be easily accessible (such as real or reactive power dispatch controls), require description of trip codes for debugging, or the ability to adjust or disable protection models.

MOD-026-2 Requirement R1, Part 1.2 pertains to EMT model specifications by TPs and PCs in support of MOD-026-2 R3. Here, the TP and PC may specify which IBR plants and facilities and which HVDC facilities and FACTS devices they require EMT models of for supporting the EMT-based positive sequence model validation under R3. Note that the exception to the EMT model requirement will limit the facilities for which verified EMT models need to be submitted by a Generator Owner or Transmission Owner even if a TP should require them.

Requirement R1, Part 1.2 also requires the Transmission Planner to specify and document the acceptable EMT software, model format, and level of detail of the IBR generation plants/facilities, HVDC facilities, and FACTS devices for which EMT models are required. Examples of such specifications include the following:

1. The Transmission Planner should specify the type of software used and version (including compiler version).
2. To ensure the model is compatible with nearby models for larger studies, the Transmission Planner should define the range of simulation time-step sizes the model must be capable of operating over.
3. Regarding the level of detail, the Transmission Planner may require full detailed modeling of phase-locked-loops (PLL) and fast current controls, power electronic switches or equivalent switching models (as opposed to average source models).
4. For accuracy, the Transmission Planner may specify usage of actual code or require hardware validations/benchmarks or may prohibit models from using certain off-the-shelf library blocks (such as using a generic phase-locked-loop (PLL) control block rather than modeling the actual PLL control block).
5. It is recommended that the Transmission Planner describes the planned use for the EMT model (such as weak-grid studies, sub-synchronous resonance, unbalanced faults, or special islanding or over-voltage protection studies), so that the vendor can ensure an appropriate level of detail.
6. The Transmission Planner should also indicate if balance-of-plant equipment should also be included in the model, including the Power Plant Controller (PPC).
7. For ease-of-use, the Transmission Planner may specify that certain controls or outputs be easily accessible (such as real or reactive power dispatch controls), require description of trip codes for debugging, or the ability to adjust or disable protection modules.

Part 1.3

Requirement R1, Part 1.3 requires the TP and PC to document and make available to GOs and TOs any criteria that would be used to assess acceptability of the verified and validated dynamic models and accompanying documentation. It presumes that the usability criteria of MOD-026-1 Requirement R6 (Parts

6.1 – 6.3) and MOD-027-1 Requirement R5 (Parts 5.1 – 5.3) would be included. Having defined and known criteria creates efficiency in the review process, reducing review times and submission overheads, and increases the likelihood that models will be accepted by the Transmission Planner without multiple revisions from Generator Owners/Transmission Owners.

It is recommended that the Transmission Planner is familiar with the most recent industry guidance to inform their acceptance criteria. For example, *NERC BPS-Connected IBR Modeling and Studies Technical Report (Chapter 1)* provides a list of recommended questions to ask when receiving dynamic models, which provide a basis for the Transmission Planner when receiving a model. For PV plants using the WECC generic models, Transmission Planners can follow the steps in Sections 4.2 and 4.3 *WECC's Solar Photovoltaic Power Plant Modeling and Validation Guideline* to verify that model control flags are set appropriately. For parameterization checks, Transmission Planners may also choose to identify parameters that are technically acceptable, but violate interconnection requirements, such as inappropriate droops, deadbands, protection settings, or control modes. The Transmission Planner may also identify the specific large disturbance tests that must be simulated by a Generation Owner/Transmission Owner on both EMT and positive sequence IBR models for benchmarking comparisons.

Usability refers to the ability of a Transmission Planner and Planning Coordinator to utilize a model with their existing tools and processes. It is possible for a model to be usable when connected only to an infinite bus and then it fails when simulated as part of a larger power system. *Interoperability* refers to the ability of a model to be used in conjunction with other existing models. The two terms are closely related and besides usability criteria in MOD-026-1 Requirement R6 (Parts 6.1 – 6.3) and MOD-027-1 Requirement R5 (Parts 5.1 – 5.3), some other items that may be specified to ensure usability and interoperability include:

- Documentation or instructions
- Time steps the model should be capable of running at
- Pertinent controls and/or options accessible to the user such that they can manipulate the model
- Reporting or diagnostics to enable a user to identify performance issues
- Ability to accept external reference values
- Ability to be scaled
- Ability to be interconnected with other models
- Specifications for software and its version
- The Fortran version that is required for it to run
- Initialization time
- Support simulation tool features such as "snapshots" or "multiple runs"
- Does not rely on global variables

To meet the acceptance criteria for *initialization*, models should be able to initialize without errors and flat run-in no-disturbance simulations.

Rationale for Requirement R2

MOD-026-2 Requirement R2 requires GOs and TOs to provide verified and validated positive sequence dynamic models, associated parameters, and supporting documentation to the Transmission Planner in accordance with the process defined in Requirement R1. The goal is to make sure that models used in planning studies accurately reflect in-service equipment. The requirement is supported by Attachments 1 and 2, which detail minimum model and periodicity requirements.

Among the major changes in MOD-026-2 compared to MOD-026-1 is the expanded scope introduced under Requirement R2. MOD-026-1 focused primarily on excitation systems and plant Volt/VAR control functions for synchronous generators. MOD-026-2 better clarifies applicability to inverter-based resources (IBRs), and adds synchronous condensers, FACTS devices, and HVDC systems by explicitly referencing each technology in the applicability section and verification requirements.

MOD-026-2 also replaces the previous narrative formatting with structured tables (Attachment 1 Table 1.1 for synchronous machines and Attachment 1 Table 1.2 for IBRs, FACTS, and HVDC) to ensure uniform industry implementation. These tables specify the minimum required model elements and site-specific data for each technology. MOD-026-2 also explicitly includes Model Verification (though not Model Validation) of enabled protections functions and limiters that may cause tripping or alter performance during system disturbances.

Requirement R2 – General Rationale

This requirement ensures that positive sequence models used for dynamic simulations are representative of actual equipment.

Attachment 1 defines the minimum required components of verified models, distinguishing between synchronous resources (Table 1.1) and inverter-based resources (Table 1.2). Attachment 2 defines periodicity requirements for Model Verification and Model Validation, ensuring accurate models throughout the facility life cycle. This reflects the understanding that models can become outdated due to various reasons over time. By implementing a 10-year maximum validation cycle (with shorter timelines if changes occur), Requirement R2 ensures continuous model quality management.

Requirement R2, Part 2.1 requires that the models submitted reflect the in-service configuration of the facility and physical equipment.

Requirement R2, Part 2.2 requires verification of site-specific, configurable parameters that can be confirmed by the GO or TO. Parameters such as exciter gains, governor droops, limiter thresholds, and PPC settings significantly impact the dynamic behavior of the facility. This requirement ensures model parameters are consistent with field settings.

Requirement R2, Part 2.3 requires validation of, at minimum, the items identified in parts 2.3.1 and 2.3.2 as subject to Model Validation. For synchronous generators (Table 1.1), this includes excitation controls and governor controls but not limiters and protection systems. For IBRs and HVDC/FACTS facilities (Table 1.2), this includes PPCs, voltage controls, and reactive and active power (or frequency) controllers, but likewise not protection and limiting functions.

Inclusion of these elements addresses gaps identified in past NERC disturbance analyses (e.g., NERC's Odessa reports), where insufficient modeling of protection elements led to widespread tripping of IBRs. Capturing such dynamics in positive sequence simulations improves planning accuracy and addresses these reliability risks.

Rationale for Requirement R3

MOD-026-2 Requirement R3 has been drafted with the intent of providing clear requirements to verify that EMT models represent in-service equipment at each IBR facility. As Inverter-based Resources (IBR) continue to interconnect to the bulk power system (BPS) across North America, Transmission Planners and Planning Coordinators are faced with challenges relying solely on positive sequence dynamic models to ensure reliable operation of the BPS. The following challenges have been identified in an increasing number of networks across North America and around the world:

- The RMS positive sequence simulation platforms, by design, are generally not suitable for capturing the dynamic response of inverter-based resources for unbalanced fault conditions.
- Due to the aforementioned point, any individual phase-based controls or protection cannot generally be modeled to complete accuracy in an RMS positive sequence simulation platform. For this reason, the RMS positive sequence dynamic models have limitations in precisely assessing ride-through performance during unbalanced faults often performed during interconnection and planning studies.
- In areas of high penetration of inverter-based resources or low short-circuit strength networks, the existing state-of-the-art generic RMS positive sequence dynamic models may encounter numerical issues that pose challenges for Transmission Planners.
- The RMS positive sequence 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.
- Due to the numerical issues and simplified modeling assumptions described above, the existing state-of-the art generic RMS positive sequence dynamic models are often unable to identify controls instability or controls interactions with neighboring facilities or sub-cycle inverter tripping.
- As documented recommended in the *NERC Odessa Disturbance Reports* (2021, 2022), most of the causes of solar PV reduction identified in these events and other past events analyzed by NERC cannot be properly represented in positive sequence dynamic models. High quality, vendor-specific EMT models are required to identify these causes of tripping.

A combination of modeling challenges drives the growing need for EMT modeling and studies for Inverter-based Resources, particularly in areas of growing penetration of inverter-based resources or low short-circuit strength. These areas may be wider areas of the BPS or may be local pockets of Inverter-based Resources that often do not include any nearby synchronous generation or loads. The *NERC Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources* recommends including real-code EMT modeling requirements for all newly interconnecting Inverter-based Resources to the BPS and also recommends benchmarking the RMS positive sequence dynamic models with those EMT models. All the issues described above are dependent on accurate parameterization of the models to match the equipment installed in the field. Inaccurate parameterization of any model (RMS positive sequence or EMT) can lead to misidentification of potential BPS reliability issues.

Requirement R3, Part 3.1. similarly to R2, Part 2.1, requires that the EMT models submitted reflect the in-service configuration of the facility and physical equipment.

Requirement R3, Part 3.2 requires verification of site-specific, configurable parameters that can be confirmed by the GO or TO. Parameters such as exciter gains, governor droops, limiter thresholds, and PPC settings significantly impact the dynamic behavior of the facility. Similarly to R2, Part 2.2, this requirement ensures EMT model parameters are consistent with field settings.

Requirement R3, Part 3.4 requires the validation of IBRs at the individual inverter unit or wind turbine level. This is relevant to the dispersed nature of IBRs by ensuring that models of these most important components of IBR plants/facilities that most affect the dynamic performance during system disturbances are validated against whatever tests would be run by the OEM at their factory or product test facility before being assembled into the overall plant/facility per R3, Part 3.1.

Large Signal Disturbances

In the context of MOD-026-2, a large signal disturbance is typically the result of a fault on the transmission system, a loss of generation, a loss of a large load, or a switching of a heavily loaded transmission line. *IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems* (2022), and *BPS-Connected Inverter-Based Resource Performance*, *NERC, September 2018* characterize large disturbances in the context of IBRs as disturbances that result in the IBR unit terminal voltage going outside of the continuous operating range. Such disturbances may result in activating nonlinearities in the control, such as limits (amplitude and/or rate of change), control mode switching (e.g., switching to FRT control mode), and/or actions to protect the equipment. Since these nonlinearities depend on non-standardized and potentially proprietary control design, this will vary among the equipment manufacturers. Therefore, it is not possible to identify a voltage magnitude, frequency, or phase angle change that describes when such nonlinearities occur that are consistent across all IBRs.

Large-signal response of IBRs is dependent on programmable control and protection functions and therefore cannot confidently be extrapolated from small-signal staged testing. Additionally, large-signal validation by staged testing is not feasible and events of a large-signal nature are unlikely to occur at convenient intervals or at all. An alternate means of large-signal positive sequence model validation is necessary. The use of EMT modeling and simulation as a substitute for large-signal staged testing or actual large disturbance events comprises such alternate means. Requirement R3, Part 3.1 device testing first ensures that the IBR unit model response is consistent with or emulates the response of the supplied equipment. When referring to an IBR unit, the DT created a footnote within MOD-026-2 to define the term. This footnote was worked in previous drafting efforts and aligns as closely with the IEEE 2800 definition as possible. A diagram located in the Reference section can visually represent what an IBR unit is. Although the standard intentionally does not specify IBR device test procedures or methods related to Requirement R3, Part 3.4, IBR device tests should be hardware specific and may include factory type tests, hardware in the loop tests, or other manufacturer tests to ensure the EMT model's large signal response emulates the supplied equipment. Aggregate EMT plant or facility models are then formed by adding other plant element models, including the similarly hardware test validated power plant controller model and any auxiliary dynamic device models such as statcoms, to the validated equivalent(s) of the individual inverter units into an overall plant model per Requirement R3, Part 3.1. The aggregate EMT plant or facility model is also subject to staged test or measured system disturbance validation under Requirement R3, Part 3.3.

The verified/validated EMT plant model then becomes the platform against which the positive sequence plant model may be validated in Requirement R3, Part 3.5. The specific large-signal simulation tests that must be run on both EMT and positive sequence models for benchmarking comparisons should include balanced and unbalanced faults, delayed clearing phase-ground point of interconnection faults, temporary or transient over-voltages, rates of change of frequency (ROCOF), varying short circuit levels (or ratios), and phase angle jumps as may be specified by the Transmission Planner under Requirement R1, Part 1.3.

Large disturbance tests on individual IBR projects may be run on both EMT and positive sequence test systems that consist of the project model connected to a controllable bus representing the point of interconnection (POI) and a Thevenin equivalent representing the transmission grid. It is not necessary to model the interconnected transmission system in detail to run these tests. The voltage, voltage phase angle, frequency, and short circuit level at the POI bus may then be varied to simulate various large-signal disturbances under various system conditions.

If positive sequence model verification were to exclude the IBR EMT model benchmark step in Requirement R3, Part 3.5, the positive sequence plant model large-disturbance behavior would need to be validated directly from the unit level device tests alone. Original Equipment Manufacture (OEM) unit tests may be limited in their ability to characterize system conditions and events that cause IBR instability and tripping, which behaviors must be represented accurately in transmission planning and operational studies. Positive sequence IBR models are also limited in their ability to represent protection and controls that affect instability and tripping. In contrast, EMT plant models validated by unit level device tests are not theoretically limited in their ability to represent these behaviors and therefore are more apt to represent the stable operating boundaries of IBR plants accurately. The chief advantage of applying EMT simulations to validate positive sequence models, then, is that simulations may be pushed to those operating boundaries and beyond whereas OEM unit tests would not do that. It is only in this identification of boundaries that it enables the Transmission Planner to assess the ability of the positive sequence plant models to represent the large-disturbance behavior.

Rationale for Requirement R4

MOD-026-2 Requirement R4 incorporates the intent and aspects of MOD-026-1 Requirement R4 and MOD-027-1 Requirement R4. This requirement is intended to ensure that updated models and accompanying documentation are provided to the Transmission Planner within a reasonable timeframe after any modification to an existing facility that changes the dynamic performance of that facility. If changes to dynamic performance result from these equipment or facility modifications, the dynamic models used to assess their impact on the grid also need to be revalidated and resubmitted so Transmission Planners may study the reliability impact of the modified facility on the grid. The team added "or as mutually agreed upon with the Transmission Planner" to provide flexibility to Generator Owner(s) and Transmission Owner(s) to provide models more than 180 calendar days after a change if an extension is required and is agreeable to the Transmission Planner. The timeline has been incorporated within the Requirement's language, as industry and the team felt it was most appropriate in the requirement language itself rather than in the Periodicity Table.

Rationale for Requirement R5

MOD-026-2 Requirement R5 incorporates the intent and aspects of MOD-026-1 Requirement R3 and Requirement R6 and MOD-027-1 Requirement R3 and Requirement R5. This requirement is intended to ensure that the Transmission Planner reviews the submitted model and accompanying documentation and provides feedback to the Generator Owner/Transmission Owner within a reasonable time either accepting or rejecting the submitted model. If the Transmission Planner determines the model(s) and accompanying documentation are acceptable, the Transmission Planner must provide a written notification to the Generator Owner or Transmission Owner. In addition, the Transmission Planner must provide its Planning Coordinator either a written notification or the accepted model(s) and accompanying documentation. The team provided flexibility to the Transmission Planner to account for varying processes for communicating updates between Transmission Planners and Planning Coordinators. If the Transmission Planner determines that the model and accompanying documentation does not meet the acceptance requirements established in Requirement R1, it must provide clear and sufficient information for the Generator Owner or Transmission Owner to understand and correct the deficiency. The 90-day timeline was carried through from the previous version of MOD-026-1.

Rationale for Requirement R6

MOD-026-2 Requirement R6 incorporates the aspects of MOD-026-1 Requirement R3 and Requirement R5, and MOD-027-1 Requirement R3. This requirement is intended to ensure that the Generator Owner/Transmission Owner responds to the Transmission Planner's notification of denial or a request for model review within a reasonable time. If the Generator Owner/Transmission Owner determines that a model update is required to address the deficiencies, the Generator Owner/Transmission Owner should respond by providing an updated model in accordance with the requirements. Otherwise, if the Generator Owner/Transmission Owner determines that the current model should be maintained and that no update is necessary or required, the Generator Owner/Transmission Owner must provide technical justification and evidence that addresses the model deficiencies or concerns identified by the Transmission Planners. This requirement ensures the Generator Owner/Transmission Owner resolves modeling issues identified by the Transmission Planner, whether as part of the initial model review or sometime thereafter. If the model is rejected under Requirement R5, the Generator Owner or Transmission Owner has 90 calendar days to provide the updated model(s) or a technical justification for maintaining the current model. If the Transmission Planner has requested a model review, the Generator Owner or Transmission Owner has 180 days, or according to a schedule mutually agreed to by the Transmission Planner, to provide the updated model(s) or a technical justification for maintaining the current model.

Rationale for Requirement R7

Requirement R7 requires Transmission Planners to provide the current (in-use) models to a Generator Owner or Transmission Owner, as requested. This capability is essential to Generator Owners and Transmission Owners when facilities change ownership, the model is no longer on file, or there are discrepancies in model records.

Rationale for Attachment 1, Table 1.1

Attachment 1, Table 1.1, in conjunction with Requirement R2, incorporates the synchronous machine aspects of MOD-026-1 Requirement R2. This requirement adds more detail about what must be modeled for synchronous generation and synchronous condensers, such as certain limiters and protection systems, including any power oscillation damping controllers, and that the model represents in-service equipment at the facility. The representation of the voltage regulation and dynamic reactive response of synchronous generating units to transmission system voltage disturbances is necessary for accurate evaluation of system stability and reliability in dynamic simulations. Therefore, verified dynamic models and associated parameters representing generators, their excitation systems, and certain limiters and protective functions associated with the voltage regulation and reactive performance are requested.

Attachment 1, Table 1.1 in conjunction with Requirement R2 incorporates the synchronous generation aspects of MOD-027-1 Requirement R2. This requirement adds more detail about what must be modeled for synchronous generation, including certain protection systems, and that the model represents in-service equipment at the Facility. The representation of the speed governing and active power response of synchronous generating units to transmission system frequency events is necessary for accurate evaluation of system stability and reliability in dynamic simulations. Therefore, verified dynamic models and associated parameters representing prime movers, governors, load controllers, and certain protective functions associated with frequency response and active power performance are requested. Additionally, the term “turbine” was replaced with “prime mover,” which can include a turbine, reciprocating engine, or other mechanical sources of power.

Protection Systems Modeling in MOD-026-2 Requirement R2

Modeling of generator Protection Systems is critical because large disturbance phenomena can cause protection systems to disconnect generating resources from the grid. This can exacerbate grid disturbances, potentially causing cascading failures, islanding scenarios, etc. Additionally, transient behavior can result in the disconnection of units if protection system elements are set with minimal time delays. The Transmission Planner must be able to study this behavior to assess and mitigate reliability risk. Even though relays on synchronous generators and synchronous condensers may have settings compliant with the NERC protection control standards, system disturbances may cause these elements to trip regardless, affecting system response. Protection Systems that shall be modeled are those identified by the Transmission Planner under Requirement R1, Part 1.1.1 and are understood to be relay elements applied on Bulk Electric

System assets that cause the generator breaker to open and disconnect the asset, whether by directly tripping the breaker, tripping the breaker through an auxiliary relay (such as a lockout relay), or causing the prime mover to be quickly shutdown resulting in the breaker opening (sometimes called "sequential tripping"). Protection functions specified in Table 1.1 are potentially sensitive to large disturbance events and, with the exception of out-of-step, operate on quantities directly or indirectly regulated by the excitation system. The elements and functions listed in Table 1.1, frequency (and speed) elements, are of concern due to many entities setting these based on PRC-024 requirements rather than equipment capability. Similarly, many large steam turbines are set with tight frequency/speed protection settings due to the nature of steam turbine design and capability, and system events may cause these machines to trip offline, which will affect overall system performance during disturbances.

Rationale for Attachment 1, Table 1.2

MOD-026-2 Requirement R2, in conjunction with Table 1.2, incorporates the IBR generation aspects of MOD-026-1 Requirement R2 and MOD-027-1 Requirement R2. This requirement adds information that must be provided and additional details on required models for IBR generation. Table 1.2 has been drafted with the intent of providing clear modeling requirements for dispersed power producing resources outlined in BES Inclusion I4 (essentially IBR facilities), power-based electronics (FACTS devices), and HVDC terminal equipment, so that models represent in-service equipment at each facility. Table 1.2 is specific to positive sequence modeling of Volt/Var control and active power/frequency control, including any power oscillation damping controllers. This table applies to both verification and validation activities and asks for documentation of manufacturer, equipment information, modeling of hardware and control systems, and certain limiter and protection system modeling. The intent is to ensure positive sequence modeling of the volt/var and active power/frequency response of the model reflects in-service equipment at the facility.

Rationale for Attachment 2

Attachment 2 covers periodicity and certain exemption criteria. Periodicity includes the initial and subsequent Model Verification and Model Validation required time frames for existing and new plant/facilities, and the required time frame for reperforming Model Verification and Model Validation following changes to a plant/facility altering its dynamic response characteristic(s). Existing plants/facilities may continue to have subsequent Model Verification and Model Validation performed per existing GO and TO compliance schedules established under MOD-026-1 and MOD-027-1. Exemptions apply to certain qualifying identical sister units at synchronous generating plants, plants/facilities that do not have closed-loop voltage/var or speed/frequency controls or are otherwise unresponsive to system frequency or voltage deviations, and plant/facilities with low capacity factors.

Attachment 2, Row 8

Industry practice for generator and turbine modeling has recognized that some prime-mover control schemes do not vary the prime mover output significantly due to speed or frequency changes and have not been modelled in stability cases, although there has been some uncertainty and disagreement on which prime-move controls should be considered unresponsive. *NERC Reliability Guideline – Application Guide for Turbine-Governor Modeling* provides guidance to the industry on the best practices of modeling various types of control schemes that affect frequency response, including control schemes that should not be modeled. The recommendations are summarized in Table 1.2 of the guideline. The language provided in

Attachment 2, Row 12 in MOD-026-2 is intended to concisely capture the recommendations of the Application Guide on which prime movers do not need to be modeled, and thus if an applicable facility is modeled following the recommendations in Table 1.2 of the *Application Guide for Turbine-Governor Modeling*, it is following the intent of Attachment 2, Row 12.

Attachment 2, Row 9

Validation tests are exempted for conventional generators based on a 5% or less net capacity factor over the past three years. This is to account for limited opportunities to perform excitation and/or governor controls tests. Opportunities to test Volt/Var control and Frequency/Power control are more readily available for IBR based facilities and, therefore, this exemption was not intended to be available to IBRs.

Rationale for Removal of MOD-026-1 Requirement R6

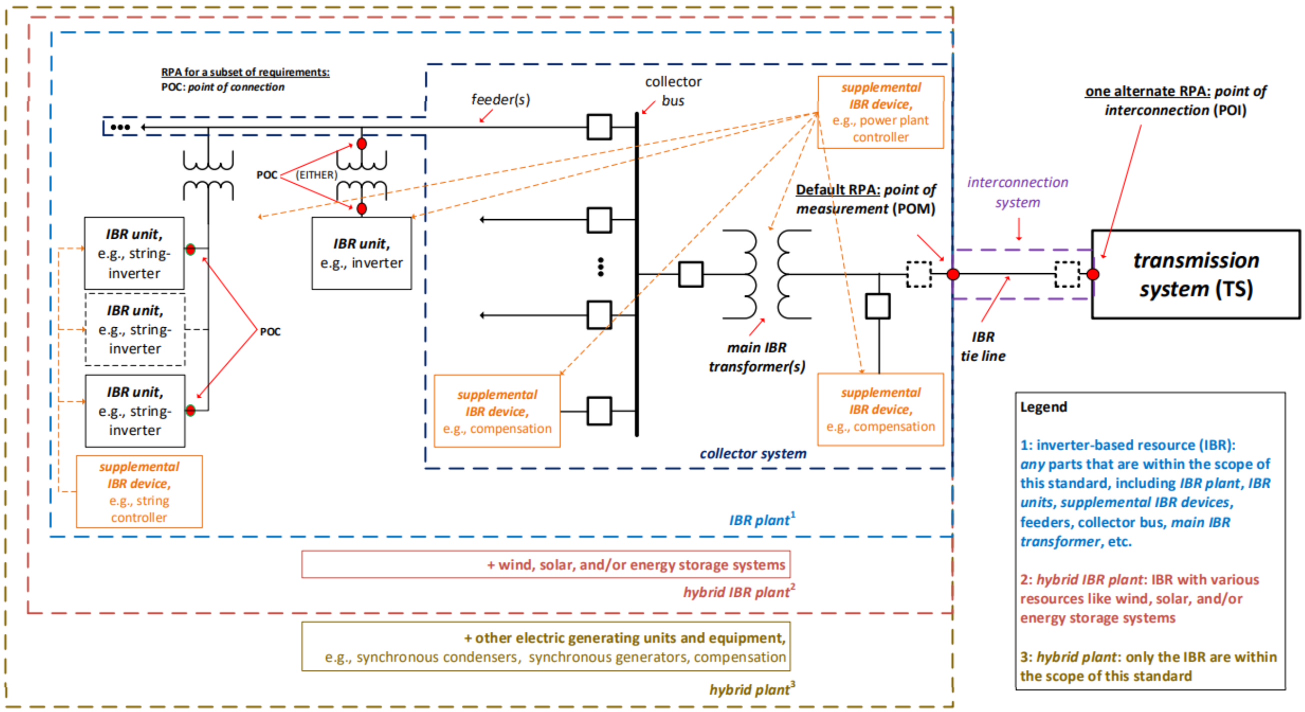
Portions of MOD-026-1 Requirement R6 are covered under two requirements in MOD-026-2. MOD-026-2 Requirement R5 covers the response the Transmission Planner is obligated to send to the Generator Owner/Transmission Owner. MOD-026-2 Requirement R1 covers the obligation for the Transmission Planner to define acceptance criteria which includes usability, as described in MOD-026-1 Requirement R6 Part 6.1 – 6.3.

Rationale for Retirement of MOD-027-1

- MOD-027-1 Requirement R1 content is covered in MOD-026-2 Requirement R7.
- MOD-027-1 Requirement R2 content is covered in MOD-026-2 Requirement R2, Table 1.1 for synchronous generation and MOD-026-2 Requirement R2, Table 1.2 for IBRs.
- MOD-027-1 Requirement R3 content is covered in a number of requirements in MOD-026-2. MOD-026-2 Requirement R1, Part 1.3 covers any acceptance criteria defined by the Transmission Planner, MOD-026-2 Requirement R5 gives options for the Transmission Owner to provide a notification of denial, and MOD-026-2 Requirement R6 defines the written response options by the Generator Owner after receiving a notification of denial or technical justification for model review.
- MOD-027-1 Requirement R4 content is covered in MOD-026-2 Requirement R4.
- MOD-027-1 Requirement R5 content is covered in a number of requirements in MOD-026-2. MOD-026-2 Requirement R1, Part 1.3 covers any acceptance criteria defined by the Transmission Planner, and MOD-026-2 Requirement R5 gives options for the Transmission Owner to provide a notification of acceptance or notification of denial. Usability requirements outlined in MOD-027-1 Requirement R5, Part 5.1 – 5.2, would be defined in the acceptance criteria under MOD-026-2 Requirement R1, Part 1.3.

Reference:

IBR unit:



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MOD-026-2 Flow chart: