MOD-033-1 Methodology Reference Document

This document was approved by NERC as "ERO Enterprise-endorsed Implementation Guidance" on 8/7/17.

Disclaimer

Revisions

Date	Version	Notes
03/16//2017	2017-1	Original Version

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Purpose

This NATF Modeling reference document, *MOD-033-1 Methodology Reference Document*[1], is intended to provide guidance, examples and approaches for performing system model validation as described in the requirements in NERC Reliability Standard MOD-033-1. The intended audience for this reference document is Planning Coordinator (PC) personnel with responsibility for conducting the various studies called for under MOD-033-1. Because of the different arrangements or relationships between PCs, Reliability Coordinators (RCs) and Transmission Operators (TOPs), MOD-033-1 R2 is not addressed in detail in this document. Under Requirement R2 the RC and TOP provide actual system behavior data (or a written response that it does not have the requested data) to the PC. Data provided may include, but is not limited to, state estimator case or other real-time data (including disturbance data recordings).

DISCLAIMER: This Reference Document does not create binding norms, establish mandatory reliability standards, or create additional requirements by which compliance with NERC Reliability Standards is monitored, or enforced. In addition, this reference document is not intended to take precedence over any company or regional procedure. It is recognized that individual companies may use alternative and/or more specific approaches that they deem more appropriate.

[1] This document reflects the collective work of 23 NATF Member companies, 18 of which serve as registered Planning Coordinators.

Topic 1: Introduction

The NERC Steady-State and Dynamic System Model Validation Standard, MOD-033-1, was created to establish consistent validation requirements to facilitate the collection and validation of accurate data and building of planning models to analyze the reliability of the interconnected transmission system. The objective of this reference document is to provide a detailed outline of a methodology to support Planning Coordinators in developing a data validation process pursuant to MOD-033-1 Requirement R1, and provide useful information pertaining to system model validation including useful tools, techniques, and options, and discuss some of the tools that used for event recording and recreation to address NERC Standard MOD-033-1. Topics include guidelines about how to go about resolving discrepancies between simulation results and actual events.

In addition, the document includes discussion of specific tasks that should be incorporated in the data validation process to compare simulated conditions to actual system conditions (e.g., mapping system topology data into the planning model). This document outlines steps to validate the planning model and provides discussions of:

- Adjusting planning models to compare with real-time power flow including generation dispatch, switch shunt position, transformer tap settings, and appropriate load adjustments. Changes to load should be made with consideration of the load dispatch and power factor in the planning model.
- Comparison of simulations using the planning models to real-time dynamic events
- Guidelines that PCs can use to determine unacceptable differences between steady-state and dynamic performance
- References to other standards that can be used to notify applicable entities of unacceptable differences in system performance
- Samples showing how individual companies are planning to comply with MOD-033-1

Figure 1 shows the overall data validation process for performance comparison in MOD-033-1, with references to sections in this reference document where more detailed information can be obtained for each specific step in the process.

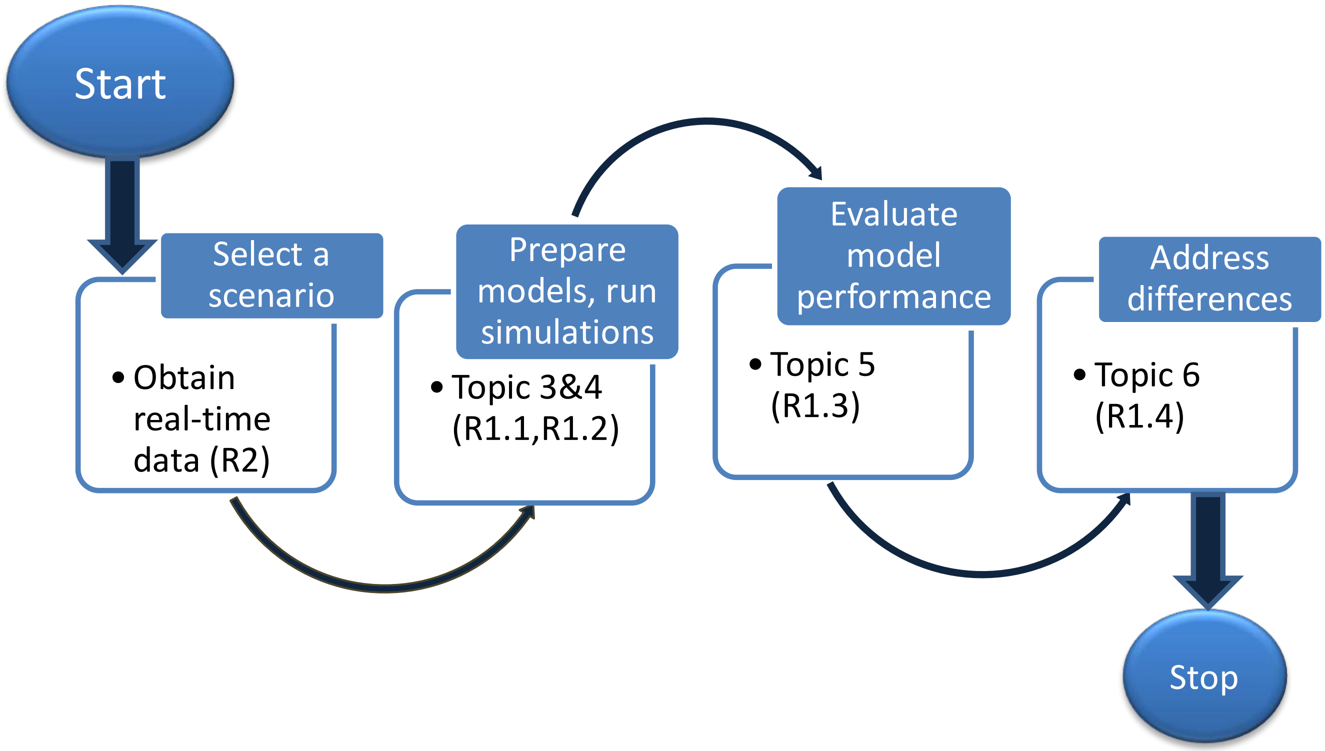


Figure 1 – MOD-033-1 Process Diagram

Topic 1 - Introductory Highlights:

This document includes approaches to MOD-033-1 compliance:

- Select a power flow model that closely matches when an event occurs
- Adjust the planning model (generation, switched shunts, transformers, and high voltage electronic power devices to real-time power flow just prior to event)
- How load should be adjusted, noting that the load distribution and power factor in the real-time power flow should be reflected in the planning case
- How a PC can use this process to set up conditions to verify the power flow model, as well as set up conditions just prior to a dynamic event for analysis (Actions to take when simulations do not correspond with real-time.)
- Guidelines to determine unacceptable differences and to reach out to applicable entities to resolve those differences

Topic 2: Scope of MOD-033-1 Data Validations

This topic describes the scope of the MOD-033-1 model validation efforts.

Validation Scope:

The purpose of this effort is to compare simulated and real-time power flows, as well as actual event response to simulated event response to verify the accuracy and if necessary identify areas requiring improvements in the planning model. The scope of validation is limited to the planning areas of each PC. The focus should be on the planning model validation within tolerances deemed appropriate by the PC. The details of accuracy are discussed in Topic 5 of this reference document. For power flow analysis, the planning model case selected should be one that most closely matches real-time conditions (e.g. heavy summer, light spring, shoulder, etc.). Either local or larger area events can be used for dynamics model validation as long as there is an adequate response to the event (as determined by PC).

During the MOD-033-1 data validation process, the PC may find issues with component models such as transmission circuits, transformers, generators, exciters, governors, Static Var Compensators (SVCs), High Voltage DC (HVDC) equipment. The PC needs to have guidelines to address discrepancies between simulations and real-time steady-state or event recordings. These guidelines may include descriptions of notification to the owners of the component (e.g., "notify the owners that a discrepancy between simulated and actual response from the element was determined during the MOD-033-1 validation process and that the data owner may need to address this"). Correcting the individual component model is the responsibility of the component owner that is either a Transmission Owner (TO), Distribution Provider (DP) or Generator Owner (GO) and is outside the scope of the MOD-033-1- model validation process. NERC Reliability Standard MOD-032-1 Requirement R3 provides language for the PC to go back to TOs and GOs for further model review.

In addition to generation and transmission component models, load models could be causing discrepancies. For steady-state simulations, typically load distribution (including the load power factor) is likely to be the main cause of differences in performance. For dynamic simulations, load model parameters, as well as load distribution could be the source of error. MOD-032-1 Attachment 1 has language that requires the Load Serving Entity (LSE) to provide steady-state and dynamic load model characteristics. However, the LSE function was deregistered with FERC's approval. If steady-state or dynamic load model performance is determined as the cause of inadequate comparisons then PC written business requirements might be needed to support requests for load model reviews. The business requirements should call for the DP to provide load information.

Exciter and governor model validation that is performed by the GO is specifically covered by MOD-026-1 and MOD-027-1 standards and that review is outside of the scope of MOD-033-1.

Topic 2 - Scope of MOD-033-1 Data Validations - Highlights:

- MOD-033-1 verifies system power flow and dynamics system models
- MOD-033-1 provides the Planning Coordinator with an independent verification of equipment owner models
- MOD-033-1 does not replace dynamic model verification requirements under MOD-026-1 or MOD-027-1
- If discrepancies are found then the equipment owner should be notified to review the model under MOD-026-1, MOD-027-1, or MOD-032-1
- Inadequate simulations due to the dynamic performance of loads may require discussions with Distribution Providers

Topic 3: Approaches to R1.1 Steady State Model Validation

This section provides guidance for PCs in implementing a data validation process to meet the requirements of MOD-033-1 Requirement R1.1.

> **R1.1.** *Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation;*

Figure 2 below describes the steady-state review process at a high level. In this process, an existing planning power flow model is modified to match the conditions represented in an EMS case. It is preferable to modify an existing planning power flow model since it is less likely to have solution convergence problems. Additionally, if the same conditions are to be used for dynamic model validation a power flow model that is compatible with dynamic data should be selected. The remainder of this section describes each step in further detail.

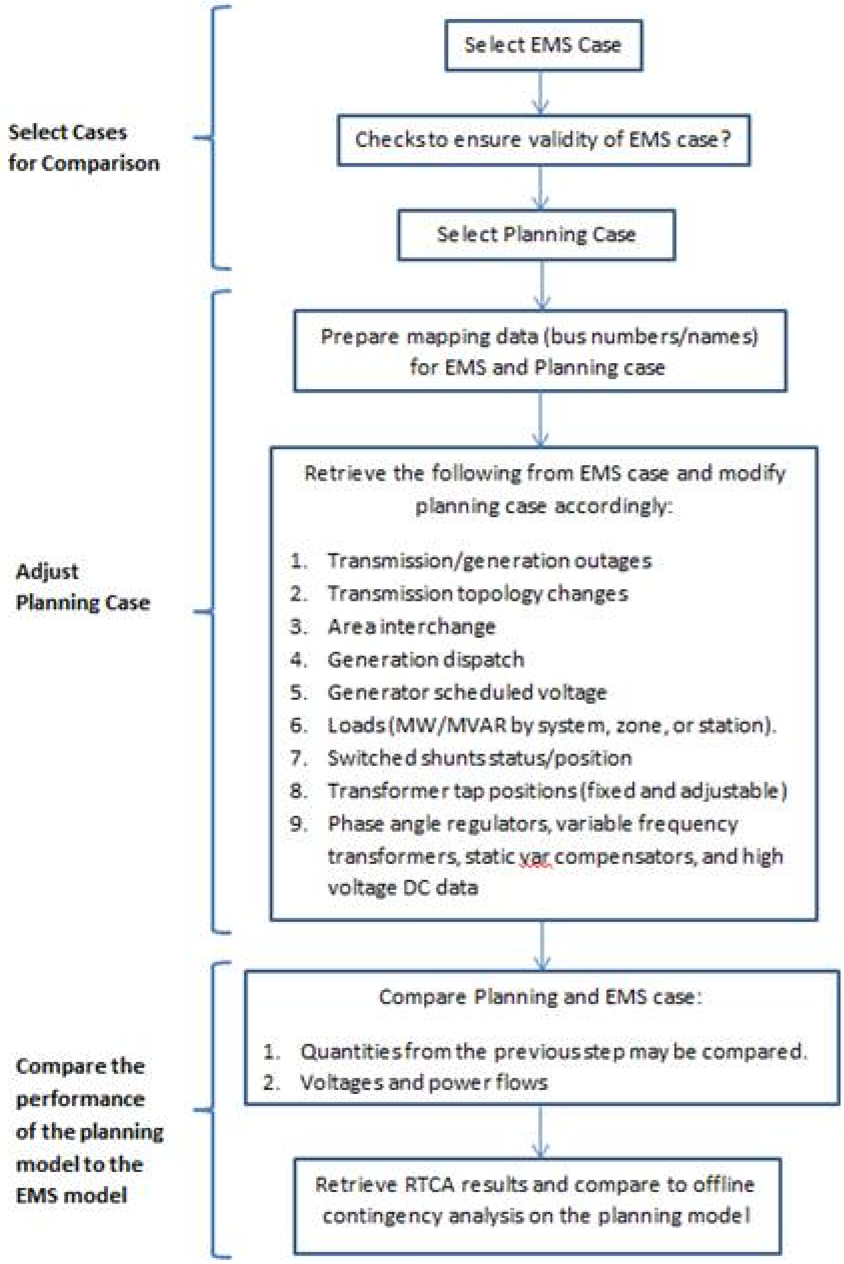


Figure 2: Comparison of the Steady-State Planning model to Actual System Behavior

Selecting Cases for Comparison

<u>Select EMS and Planning Models for Comparison</u>

MOD-033-1 Requirement R2 requires each Reliability Coordinator and Transmission Operator to provide actual system behavior data (or a written response that it does not have the requested data) to any PC performing validation under Requirement R1 within 30 calendar days of a written request. Data such as, but not limited to the state estimator case or other real-time data (including disturbance data recordings) necessary for actual system response validation must be provided.

PCs typically create multiple power flow cases representing various seasons, load levels, and transfer levels. One method of validating the power flow model is to capture real-time data for conditions that are similar to existing planning models and for conditions that are known to be the most critical. Note that during a dynamic event, it may be unlikely that the dispatch will be similar to an existing planning model. Another method is to use automated or other processes as needed to closely match the planning model to actual steady-state conditions. This method is generally better if dynamics analysis will be performed. Known outages of equipment including transmission lines, series capacitors, and transformers should be modeled and dispatches adjusted to simulate real-time conditions.

Further guidelines for steady-state case preparation are found in Appendix D.

Checks to Ensure Validity of EMS Case

In order to facilitate an accurate comparison of the planning model to the real-time performance of the system, a few sanity checks should be performed on the EMS case to ensure that it accurately represents actual system behavior. The state-estimation solution parameters may be tuned to improve its convergence (minimizing erroneous, no-solve solutions in Real-Time Contingency Analysis (RTCA)) by increasing the allowable tolerances in the load flow solution and increasing the allowable MW and MVAR mismatches at buses and for the entire system. PCs should be aware that some state estimator solutions insert pseudo-injections (MWs and MVARs) at buses throughout the system. Pseudo-injections are small load injections used to make the case solve. The PC may need to review the state estimator solution for pseudo-injections and also determine what the total system power mismatch and the largest bus mismatches are if the magnitude is large in relation to actual loads. If the PC deems the state estimator solution to be unreliable during the comparison to the planning model results, the issues should be reported to the control center support staff and data from other real-time sources should be used for comparison.

Adjust Planning Model

Prepare Mapping Data for EMS and Planning Model

Some EMS programs allow for real-time data to be downloaded and analyzed within the same software as existing planning models. However, the real-time EMS case may have significant differences from the planning model that make direct comparison difficult:

- Bus names and numbers differ from the planning model. Furthermore, the bus numbers/names may change as new real-time cases are retrieved.
- Operations models use a “node-breaker” representation while planning models generally use a “bus-branch” representation
- Multiple generating units may be represented as a single unit in EMS

- Non-BES buses at power plants and distribution stations may be more likely to be explicitly modeled in the EMS model

To facilitate adjustments of the planning model and comparisons to the EMS case, the PC may map EMS data to the planning model data. This involves changing the numbers and names for all buses, areas, and zones in the EMS case to match the planning model. The PC may also choose to convert from node-breaker to bus-branch representation, modify power plant models, transformer models, etc. While some entities have developed automation to assist with some of these tasks, it is generally a labor-intensive process. However, once the EMS case is mapped to the planning model many power flow software programs contain built-in functions to compare two load flow models. The models can also be exported to Microsoft Excel to facilitate comparison as well.

Alternatively, this step can be skipped entirely. If the real-time and Planning Models are similar enough that an engineer that is familiar with the system is able to identify all facilities and perform adjustments and comparisons despite differences in the model. In this approach adjusting and comparing the models becomes more time-consuming.

<u>Adjust Planning Model to Match EMS Case</u>

There will be differences in the Planning and EMS cases that do not reflect modeling errors or incorrect assumptions since it is understood that the planning model does not consider short-term operational changes. In this step, the planning model is adjusted to the system conditions in the EMS case to enable a more effective comparison in the next step. Only the variables that are not errors and are not going to be compared are adjusted.

The items that the PC should adjust include:

1. **Transmission/generation outages**

   Planning models are not expected to include outages that are less than six months in duration. All BES outages in the EMS case should be modeled in the planning model. It may also be necessary to outage lower voltage equipment in the planning model to achieve a more accurate match.

2. **Transmission topology changes**

   The planning model will not capture temporary transmission topology changes or may have planned installations that must be removed. The planning model should be modified to reflect these topology changes.

   Note that there may be differences in transmission topology due to permanent operating practices. The PC should work with system operators to compare planning assumptions and operating practices for split buses, normally open switches, radial lines, etc. Differences in topology due to incorrect planning assumptions should be resolved. The following items may be checked:

- Impedance
- That planned generation and transmission facilities in the planning model that have not been constructed are removed from service
- Whether HVDC lines are in-service or off line.

3. **Area interchange**

   Planning models may only model firm transfers. The interchange data in the planning model should be modified to match the actual system conditions for the operating point chosen for validation.

4. **Generation dispatch**

   Planning models may not reflect the generation dispatch for the operating point chosen for validation. Generation dispatch should be modified to match the actual system conditions.

   An exception is if the PC wishes to validate any assumptions related to generation limitations or "must-run" units. In those cases, the applicable generating units should be compared to the actual dispatch before they are adjusted.

5. **Generator scheduled voltage**

   The planning model may not capture actual voltage schedule accurately since the generator scheduled voltage may change. The PC should adjust the generator scheduled voltages such that a reasonable match between terminal voltage or voltage at the Point of Interconnection (POI) of power plants is obtained. And that the reactive power output is used as a measure of success for validation.

6. **Loads**

   The PC should match loads in the planning model to real-time conditions. The PC may make assumptions about the power factor and the distribution of load between areas/zones/stations. Differences between the real-time and planning model load distribution and load power factor should be evaluated.

7. **Switched shunts status/position**

   Switched shunts in the planning model should be adjusted to match the EMS case. Fixed shunts, that cannot switch automatically and are not remotely controlled by an operator, are rarely moved. The position/status of these shunts should be compared and any differences noted and resolved.

8. **Transformer tap positions (fixed and adjustable)**

   Adjustable transformer taps in the planning model should be adjusted to match the EMS case. Fixed taps cannot be adjusted automatically or remotely and are rarely moved. The position/status of these taps should be compared and any differences found should be noted and resolved.

9. **Power Electronic and Flexible AC Transmission System (FACTS) devices**

The set points for devices such as phase angle regulators, variable frequency transformers, SVCs, and HVDC circuits should be adjusted to match the EMS case.

Note that if EMS bus numbers were mapped to planning model bus numbers in the previous step then comparing and adjusting the planning model in this step becomes much simpler. For example, code can be written to detect outages, switched shunt positions, transformer tap positions, HVDC settings, etc. in the EMS case and model them in the planning model. Most power flow software programs also have built-in functions to compare two power flow models that can be used when the bus numbers and names are the same.

If both the EMS and planning models were exported to Microsoft Excel the comparisons and adjustments can be performed either automatically or manually in Excel. Following updates to the planning model, it must be brought back into Planning simulation software, the load flow solved, and then exported back to Excel for comparisons in the next step.

Compare the Performance of the Planning Model to the EMS Model

<u>Compare Planning and EMS Case</u>

Differences in model parameters that were identified in the previous step may be documented here if they are expected to be accurately represented in the planning model. For example, the transmission topology, load distribution, load power factor, fixed shunt positions, and fixed transformer tap positions may be different from planned or assumed values.

The PC may choose to compare power flows at every location in the system. If the bus numbers and names have been matched then simulation programs have features that can flag differences that exceed a certain threshold. Otherwise, only the power flows in portions of the system, such as at certain voltage levels, at critical interfaces, or tie lines may be compared. Real and reactive power flows, should be compared. Similarly, voltages may be compared at every bus in the system or at certain voltage levels or critical facilities.

In addition to the simulation to real-time comparisons, several additional checks may be performed such as validating generator capability values (Pmax, Pmin, Qmax, and Qmin), voltage schedules, and that DER is modeled appropriately or accounted for as part of the load.

Topic 3 – Approaches to R1.1 Steady State Model Validation - Highlights

- Method 1 – When favorable conditions occur, compare real-time power flow to an existing planning model, usually a peak load model
- Method 2 – Dispatch equipment in the planning model to match real-time addressing:
    - Transmission/generation outages
    - Transmission topology changes
    - Area interchange
    - Generation dispatch
    - Generator scheduled voltage
    - Loads
    - Switched shunts status/position
    - Transformer tap positions (fixed and adjustable)
    - Power Electronic and Flexible AC Transmission System (FACTS) devices
- Compare Planning and EMS model case power flow results as described in Topic 5

Topic 4: Approach to the R1.2 Dynamic Model Validation Process

This section provides guidance for the dynamic model validation process of MOD-033-1. This process primarily focuses on comparing the performance of the actual system for the dynamic response for local events or remote events that significantly impact a studied system. MOD-033-1 emphasizes the use of local disturbances for the model validation to minimize potential modeling errors outside the PC's portion of the system that could skew the results within the PC's portion of the system. However, the PC may consider using a large, wide-area disturbance event in the validation of the dynamic models. As stated in MOD-033-1 (page 2 of 11):

"The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid."

- Using large interconnection events for system validation has the benefit that all affected PCs within a region, or RTO, may be able to use the same power flow model and dynamic model. Using a wide area case like the WECC system common case may significantly reduce time needed for base case preparation and potentially could enhance the model validation process across the interconnection.
- Note that while the wide area approach to event validation may be beneficial for some of the entities within a region, it may not be good for all entities. There may not be enough perturbation in parts of the system to validate models for equipment that are distant from the event. There could also be limitations in the sources of errors or discrepancies between actual and simulated performance when using a full system event. For example, if the frequency response outside the PC area is not accurate in the simulation, then the PC will observe errors that are not within its area. The PC probably will not have sufficient data or information to pinpoint and correct these errors outside its PC footprint.
- For MOD-033-1 analysis, the wide area model itself can be used for dynamic event analysis for greater accuracy and improved modeling for event reviews.
- Local events should be used per the NERC standard. If possible a number of local events should be analyzed to validate various parts of the system. Local events may excite local generation more than wide-area events and provide a

more useful verification of generator models however; this approach may not lead to identifying the largest model discrepancies within a wide-area model.

- In general, it is best to use a combination of wide-area and local events for comparisons to achieve improved model accuracy.

Methodology

Dynamic model validation will require adjustments to the planning power flow base case to pre-contingency event conditions. While the steady-state and dynamic system models can be validated separately, it may be more efficient to use the same event and power flow model for validation of both (R1.1and R.1.2). Note that a steady-state model validation does not require having a system event while the dynamic model validation can be performed only when there is a dynamic local event and the event data is available from disturbance monitoring devices nearby. This section describes steps for dynamic model validation in detail.

Selection of Events

The first step in dynamic analysis for MOD-033-1 is to select an event(s) against which system model response will be validated against actual system response. MOD-033-1 Requirement R2 requires Reliability Coordinators and Transmission Operators to provide disturbance data recordings to the PC.

The following dynamic events may be considered if proper disturbance monitoring data is available.

1. AC or HVDC Transmission line switching (including opening and closing) events without a fault
2. Generating unit(s) tripping or oscillating events
3. Transmission system faults[2] – three-phase, single-phase, multi-phase, normal or delayed clearing, uncleared faults[3], or other low voltage conditions for transmission elements including lines or transformers
4. HVDC tripping or run backs
5. AC or DC controls (mis)operations
6. Planned or unexpected large load tripping, load shedding, or other frequency events;
7. Large FACTS device switching, failure, or operation
8. System islanding or loss of synchronism events
9. Other large system swings exhibiting significant voltage, load or frequency fluctuations, particularly with low damping ratio and high amplitude

[2] PMU filtering needs to be considered when using fault event near the terminals of the generating unit(s) under test.

[3] Uncleared faults often have more complex fault interactions with changing fault impedance. In addition, these events often have actual protection schemes that are not modeled operate to clear transmission or generation elements on the system. In these cases, these events should not be used for validation purposes, as it is hard to accurately represent the event in positive sequence simulation tools with the models available in the planning cases.

Some events may not be suitable for MOD-033-1 validation due to limitations in the simulation tools. These events may include:

- Asymmetric events such as sustained unbalanced flows such as single pole reclosing
- An event that occurred when generating units are ramping up or down (e.g., due to schedule changes). In study simulations, during the initialization process, we assume that all generating units are static with fixed outputs, but over the course of the simulation timeframe which may last up to 60 or 120 seconds, some of the units may ramp up or down.
- Evolving fault events (single line to multi-line or three phase) that could cause large imbalances during the fault.

Data Acquisition

Once a system event is selected, the data typically obtained from the state estimator, Supervisory Control and Data Acquisition (SCADA), Dynamic Disturbance Recorders (DDRs) and Phasor Measurement Units (PMUs) for the system and the time duration being simulated should be acquired. The data can be requested from the RC and/or TOPs (per MOD-033-1 R2). The RC can provide a snapshot from their State Estimator (SE) data prior to and immediately after the event. Appendix B contains additional information about data acquisition equipment

Event sequence information should be requested from the TOP(s) or RC in the area that the event occurred. TOPs typically have the most accurate information for events that occur in their footprint.

Further guidelines for dynamic case preparation are found in Appendix D.

Power Flow Set up for Dynamic Model Validation

Once a system event for model validation is selected, the state estimator, SCADA data, and event sequence are to be acquired. The initial power flow validation serves to ensure data accuracy of the base case pre-event conditions adjusted by real-time SCADA measurements. Only event sequence needs to be investigated, prepared, and then included in the study. The case to be used for dynamic model validation should have pre-contingency operating conditions that match the actual system conditions prior to when the event occurred. The power flow case for dynamic model validation should be set up using the same approach as described in Topic 3.

Dynamic Model Validation

Preparation of Dynamic Data File

Once the power flow model and dynamic data are prepared, a few transient runs should be performed using the new dynamic data. A no-disturbance simulation should produce flat lines; a disturbance simulation e.g., ring-down simulation, namely apply and remove a temporary fault without tripping any element should produce traces that initially oscillate but damp out acceptably.

Creation of Sequence of Events File

The next step is to create an accurate sequence of events and switching file. The sequence of events can be based on relay records; Sequence of Event records (SERs), SCADA, dispatcher logs, etc. Sequence component currents and voltages are recorded by relays. This data may be used for comparing with the simulation results. For that purpose, proper quantities (such as MW and Mvar out of a generating unit, Mvar output of a dynamic reactive/var device, MW and/or Mvar flows on a transmission element, voltage magnitudes at major buses, etc.) should be monitored when setting up the dynamic simulation

Run the Dynamic Simulation

Traditionally, dynamic simulation duration is 10 to 20 seconds. After 10-20 seconds, AGC, tap-changers, slow acting capacitors, responses and other secondary controls would need to be accounted for and typically these elements are not represented in transient stability models. For further discussion of AGC action, see Appendix C- AGC Limitation. Once the simulation is complete, a comparison of the dynamic simulation results to the actual dynamic system event data should be made. For details on the parameters to compare and what is acceptable performance of this comparison, see Topic 5.

Topic 4 Approach to R1.2 Dynamic Model Validation - Highlights

To compare dynamic model to actual system response:

- Select local or wide-area events
- Confirm the event selected results in perturbation of the PC area
- Obtain real-time data before and after the event generally from SCADA or EMS
- Sources of real-time data during the event are likely to be DDRs or PMUs
- Ensure that a no-disturbance simulation produces flat line results

Topic 5 addresses acceptable performance guidelines

Topic-5 - R1.3 Guidelines to determine unacceptable differences

Due to the complexity involved in model validation, the performance should be evaluated using engineering judgment. To facilitate the evaluation, PCs should use review the results closely to decide when performance is acceptable. Table 1 lists recommended guidelines for acceptable differences between the simulated and actual steady-state model validation (R1.1). Values shown in Table 1 are illustrative. It is recognized that each PC should develop values that are appropriate for their PC footprint and review these values, as MOD-033-1 evaluations are ongoing. The PC may choose some of the parameters from Table 1 in the development of their list of acceptable values.

Table 1 provides evaluation criterion, both for percentage differences and absolute differences for the real and reactive power flows to be applied on major transmission facilities as determined by the PC. For branches with low MW/Mvar, it may be more appropriate to use absolute values. For example, comparing a 230 kV branch with a modeled flow of 5 MW and a state estimator flow of 7.5 MW would yield a difference of 50%. Conversely, a circuit with 500 MW and a state estimator flow of 750 MW would be deemed a substantive difference and should be addressed. Allowing for a percentage difference, as well as an absolute difference in the comparison allows such flows to be accommodated. Alternatively, for non-zero impedance lines, the branch flow can be normalized based on branch normal continuous rating (Rate A) and % difference can be examined. For example, a line rated for 845 MVA loaded at 211 MVA in S.E. case is loaded at 25% of normal continuous rating and same circuit loaded at 279 MVA in Planning case is at 33% of the normal continuous rating. The difference in percentage normal loading is equal to 8%. This matrix is capable of accounting the combined impact of real and reactive flows on the line, irrespective of line normal ratings and kV class. The PC may select sample lines and buses for determining whether the comparisons are within the acceptable differences. The PC may select from more critical facilities to provide samples or use other methods as necessary.

Table 1 – Guidelines to identify acceptable differences between simulated and real-time data for steady-state validation[4]

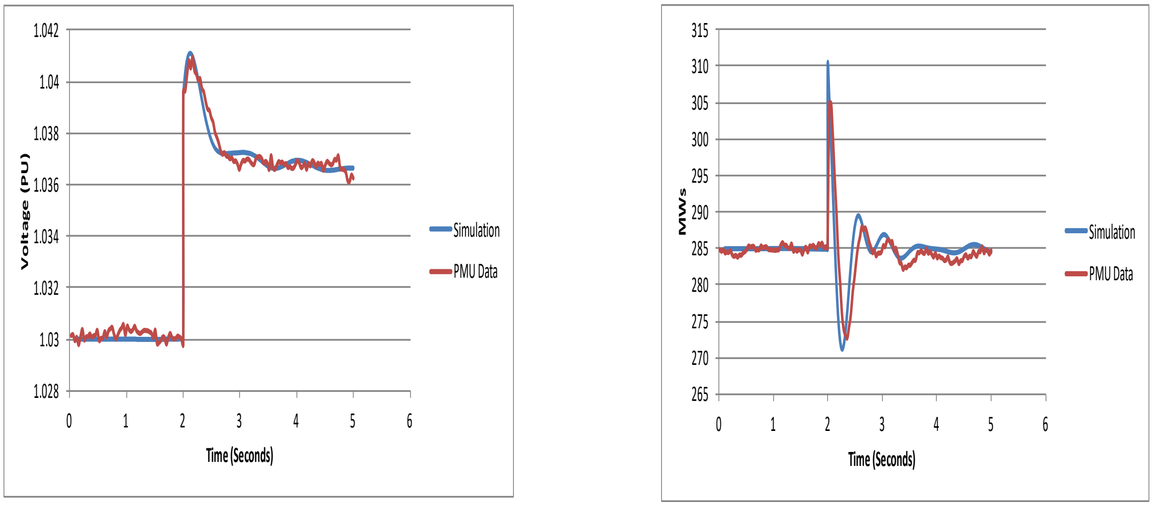
Quantity	Acceptable Differences
Bus voltage magnitude	±2% (≥500 kV) ±3% (230≥kV≥345 kV) ±4% (100>kV>230 kV)
Generating Bus voltage magnitude	±2%
Real power flow	±10% or ±100 MW
Reactive power flow	±20% or ±200 Mvar
Difference in % normal loading	±10% based on branch normal continuous rating

Per MOD-033-1 Application Guideline (page 9 of 11): *"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 PC should determine that the measured and simulated response exhibit similar dynamic response. The following guidelines should be considered when determining if the comparison for dynamic event is acceptable or not.

1. The simulation results, such as voltage or MW flow, should be plotted on the same graph as the actual system response, as shown in Figure 3 (a) and (b), respectively.
2. The two plots could be given a visual inspection to see if they look similar or not. Engineering judgment should be applied in making this decision.

[4] Values shown in Table 1 are illustrative. It is recognized that each PC needs to develop values that are appropriate for its PC and review these values as MOD-033-1 evaluations are ongoing and improvements to the guidelines will be made.



(a) (b)

Figure 3 (a) Comparison of voltage plots and (b) comparison of MW flow plots for dynamic local event.

Topic 5 -R1.3 Unacceptable Difference Guidelines - Highlights

- Explain engineering judgment when reviewing power flow and dynamic simulation comparisons
- Use the numerical guidelines provided in Table 1 to determine acceptable results for power flow comparisons
- Compare side by side real-time and simulated event plots for dynamics
- Apply engineering judgment when results do not match for dynamics.
  - Example 1 - If there is PMU data from a nearby generator then compare the generator response.
  - Example 2 - In the case of frequency validation, attention should be paid to governor modeling

Topic 6: R1.4: Guidelines to Resolve Unacceptable Differences

Under MOD-033-1 R1.4, each PC must have Guidelines to resolve the unacceptable differences in performance between the power flow model to actual system behavior or existing system planning dynamic model to actual system response. Topics 3 and 4 of this NATF Reference Document show how to match steady-state conditions and dynamic events with simulations. Topic 5 of this guideline provides a methodology to determine when comparisons show that models or performance is unacceptable. Some steps to resolve unacceptable differences include:

- Checking the calibration of SCADA, PMU and DFR equipment to ensure they are providing accurate data.
- Checking the validity of load models and parameters where practical.
- Discussions with equipment owners when models are determined to be inaccurate.
- If a specific model inaccuracy cannot be determined, it may be necessary to gather more event data.

Outreach to Equipment Owners

Several NERC standards have language that address reaching out to equipment owners to validate their models.

If an unacceptable difference is identified by the PC using a DDR or PMU directly monitoring a generating facility at the POI, then NERC MOD-026-1 requires an applicable GO to verify generator excitation system or plant volt/var control function models and the parameters used in simulations for the Transmission Planner (TP). When simulations do not match actual real-time data, then the TP, under MOD-026-1 Requirement R3 or R5, can request that the GO verify the excitation system model and parameters. The GO must then provide a written response with the technical basis for maintaining the current model, model changes, or a plan to provide verification in accordance with the standards R2 requirement. NERC standard MOD-027-1 is similar to MOD-026-1 except that it requires verification of the governor and associated functions and MOD-027-1 R3 requires that three events be used to trigger a request for GO governor model review. MOD-026-1 R3 only requires a TP to provide supporting evidence that a GO model review is needed based only on one event. Refer to the standards for further details regarding regional applicability and review requirements for each standard.

Under NERC MOD-026-1 and MOD-027-1, GOs may have a long-term plan to validate models. In some cases, it will be better to use an "interim model" based on a parameter update that can be determined from disturbance data. NERC MOD-026-1 and MOD-

027-1 Requirement R2 support the use of measured system disturbance data to provide interim parameters for the model.

NERC MOD-032-1 Requirement R3 provides a trigger for the PC to call for reviews of steady-state and dynamic data as listed in Attachment 1 of that standard. NERC MOD-032-1 applies to generators that meet the NERC registration criteria under the BES definition (i.e. greater than 20 MVA for a single unit or greater than 75 MVA aggregate generation connected at 100 kV or above).

Appendices E1 and E2 contain sample-letter forms that can be used to reach out to equipment owners for further model validation review. The letter will be tailored depending on the discrepancy found, the standard that can be used to request equipment owners to review models and the functional entities referenced in the standard.

Topic 6 – Approaches for R1.4 Resolving Unacceptable Differences - Highlights

- Check for inaccuracies that may be due to equipment set-up or calibration errors that cause inaccurate measurements

- Refer to the guidelines to address the appropriate standards listed below when it is necessary to request equipment owner model reviews:

  1. MOD-032-1 R3 general power flow element or dynamics differences (except load) as described in Attachment 1 unless covered by the MOD-026-1 or MOD-027-1.
  2. MOD-026-1 R3 and R5 for generator excitation system differences based on one or more events. Within the Eastern Interconnection, reviews can be for generators 20 MVA and above. See the applicability section of MOD-026-1 for further details (The request is actually made by the TP.)
  3. MOD-027-1 R3 for generator governor based on differences observed for three or more frequency events. Within the Eastern Interconnection, reviews can be for generators 100 MVA and above. See the applicability section of MOD-027-1 for further details. (The request is actually made by the TP.).

  - Include technical information showing the mismatch with requests to equipment owners including the appropriate number of event responses based on the requirements of the MOD standard listed above.

A complete checklist for MOD-033-1 reviews is included in Appendix G.

Appendix

Appendix A: Reference Documents

- NERC Power System Model Validation – December 2010
- NERC Procedures for Validation of Powerflow and Dynamics Cases
- NERC Draft Reliability Guideline: PMU Placement and Installation -9/22/16
- NERC Draft Reliability Guideline: Modeling Distributed Energy Resources in Dynamic Load Models -9/22/16
- WECC -Guidelines for Validation of Powerflow and Dynamic Cases for MOD-033-1
- EPRI-"System-Wide Model Validation 3002005746".
- NATF –Modeling-MOD-033-1 Project Team Survey – September 2016

Appendix B: Monitoring Equipment

Sources of actual measurement data that can be used for dynamic model validation include:

- DDRs (Dynamic Disturbance Recorders) per PRC-002-2
- DFRs (Digital Fault Recorder) per PRC-002-2
- SERs (Sequence of Events Recorders) per PRC-002-2
- PMUs (Phasor Measurement Units)
- EMS (Energy Management System) data

This is not a complete list of possible sources. As long as the data provided is time synchronized and can provide the data with at least 30 samples per second of the positive sequence data (including voltage, real and reactive power flow, frequency, phase angle,), it could be used for dynamic model validation. The input sampling rate is typically much faster (typically in kHz) than that of the positive sequence data in the output file.

Monitoring equipment for dynamic local events is located based on what is appropriate for each PC's existing system. The number of devices will vary depending on the entity. The following considerations for locations of dynamic monitoring devices include:

- At and/or near generation facilities
- At major transmission facilities
- At major load centers
- At major interconnection points
- Bulk Electric System (BES) buses with reactive power devices

Most non-PMU recording devices will provide data as a point-on-wave quantity, at multiple samples per cycle. To effectively perform model validation, those recordings will need to be converted to RMS quantities in post-processing.

The high sampling rates necessary to capture the dynamic behavior of the system imposes a burden on the storage capacity of the recording devices, specifically, DFRs, relays, and PQ meters. For this reason, PCs will need to implement manual or automated systems to avoid event data over-writing.

Multiple software tools exist that can automatically poll DFRs/relays for new events, usually stored in COMTRADE format, and download them to a more permanent location. These tools can be installed within a substation (on a hardened PC, for example), which requires manual retrieval by someone at the station. Alternatively, if the communication system allows, it's possible to install a central retrieval unit to poll field devices and download event records to a central location for storage and analysis.

Appendix C: AGC Limitation[5]

Traditionally, dynamic simulation duration is 10 to 20 sec. and for that reason, AGC action is not simulated. During frequency events (loss of generation) for runs longer than 20 sec. AGC may act to try to restore ACE. Therefore, AGC action might be needed in order to match simulation results to PMU measurements. The following example illustrates the above mentioned remark:

Example

Simulation is performed for loss of BC-Hydro 525 MW unit loss.

Figure 1 illustrates currents through some of the WECC major 500 kV lines. Within first 20 sec. (initial and primary response) current waveform from simulation and PMU measurements match remarkably. After 20 seconds current through the line builds up due to generation secondary response (AGC action). In simulation current becomes constant since there is no AGC action modeled.

[5] WECC -Guidelines for Validation of Powerflow and Dynamic Cases for MOD-033-1

Simulation is performed for loss of BC-Hydro 525 MW unit loss.

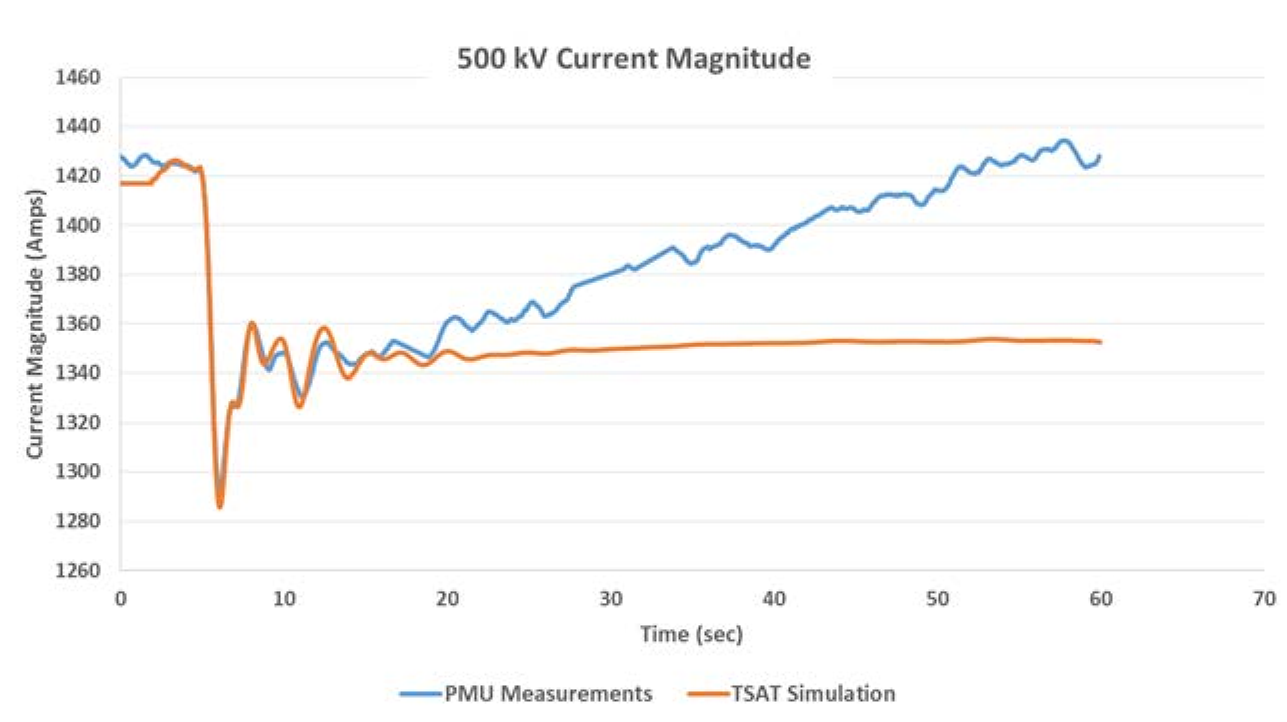


Figure 1 Impact of AGC action is reflected in increasing current over the line (blue trace). AGC action is not modeled and in simulation, after primary response current becomes constant (orange trace).

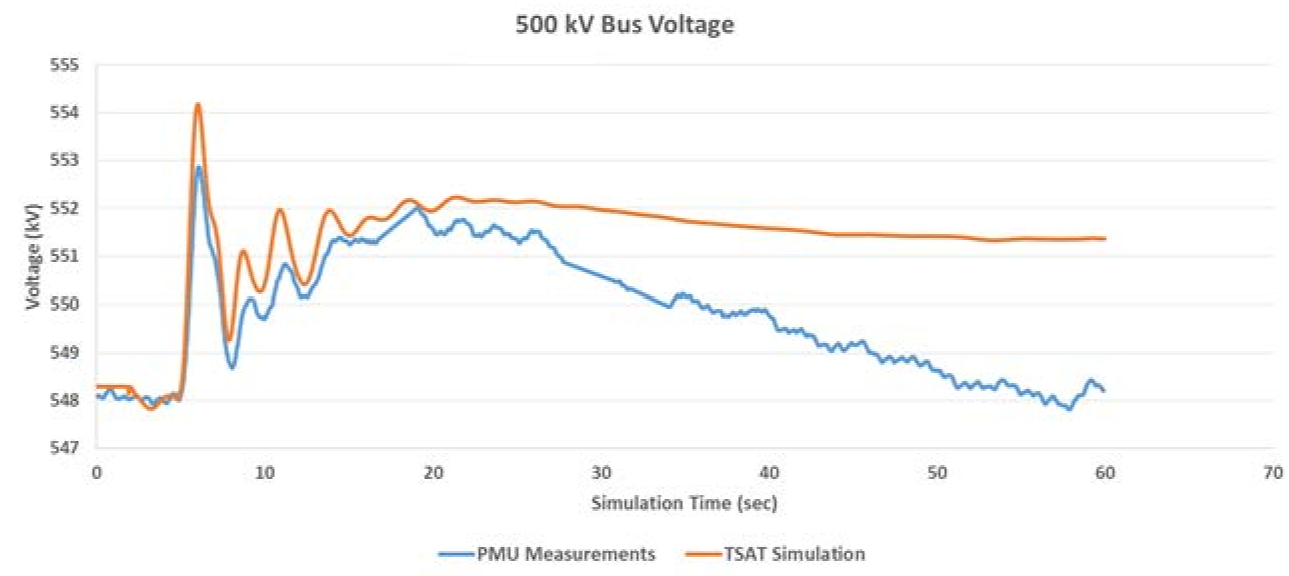


Figure 2 Increasing current over the line sag voltage (blue trace). Simulation does not model AGC action (no current increase over the line) so voltage drop remains constant (orange trace).

Appendix D- Case Preparation Guidelines

Power flow model preparation guideline	
Bus voltage magnitude **Real power flow** **Reactive power flow**	• Verify that the generation is modeled as gross instead of net values • Determine that shunt capacitors are set correctly • Verify that all state estimator loads are accounted for • Ensure the state estimator's extraneous loads are not modeled • Verify the polarity of all state estimator loads (e.g. some loads are actually sources due to PV generation) • Verify that the network configuration is modeled appropriately based on the circuit breaker and switch status (e.g. does a bus need to be modeled as a split bus due to an open circuit?) • Verify that the modeled line and transformer impedances are correct • Verify the no-load tap changers are modeled appropriately for all transformers • Verify that all planned and forced outages are modeled appropriately • Consider whether other steady-state data sources should be used where state estimator data is questionable • Consider whether differences are due to measurement error

Dynamic model preparation guideline	
Dynamic model check	Perform sanity checks such as a no-disturbance simulation which produces flat lines; ring-down test - applying and removing a temporary fault without tripping any element should produce traces that initially oscillate but damp out acceptably
Generator related dynamic modeling data	If the actual system response is measured at or near a generating facility with more than one unit in service during the dynamic local event, the generator related dynamic modeling data should be examined closely. For instance, if the voltage response does not match, then the excitation system, including power system stabilizer if equipped, should be reviewed. The PSS status for units nearby could play a key role in this effort.
FACT device dynamic modeling data	If the actual system response is measured at or near a FACTS device, the dynamic modeling data of the FACTS device should be reviewed.

Appendix E1 - Sample Letter Request for Verification under MOD-026-1 or MOD-027-1

Mr. or Ms. Equipment Owner
Via e-mail (or address information)

Dear Equipment Owner,

Planning Coordinator Name, as the Planning Coordinator for this area is working with Transmission Planner Name as the Transmission Planner for the this area in requesting that the model and parameters for the insert Equipment Owner or representative name here and facility name here facility be verified under NERC standard MOD-026-1 (excitation system), MOD-027-1 (governor). Planning Coordinator Name and Transmission Planner Name has (have) determined that the simulated dynamic response of the insert equipment owner or representative name here and facility name here is as shown in Figure 1 (Requires three events to prompt an MOD-027-1 review) along with the actual measured real-time response. This measured real-time response does not match the simulation model and review must be performed. Please provide a response with a change for the model, plan for changing or a technical basis for continued use of the existing model within 90 calendar days. The response should be provided with insert PC/TP database name or to e-mail address here.

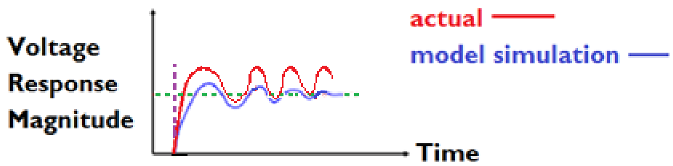


Figure 1 – Actual vs. Simulated Model Response on date(s) of event(s) – *Note Use detailed actual response diagrams (show three figures for MOD-027-1 review)*

If I can provide any additional detail for this request, please contact me via e-mail at insert e-mail address here or phone at insert phone number here.

Sincerely,
Engineer /s/

Title
PC

Appendix E2 - Sample Letter Request for Verification under MOD-032-1

Mr. or Ms. Equipment Owner
Via e-mail (or address information)

Dear Equipment Owner,

Planning Coordinator Name, as the Planning Coordinator for this area, is requesting that the model and parameters for the insert Equipment Owner or representative name here and facility name here facility be verified under NERC standard MOD-032-1 Requirement R3. Planning Coordinator Name has determined that the simulated steady-state performance or the dynamic response of the insert equipment owner or representative name here and facility name here is as shown in Figure 1 along with the actual measured real-time response. This measured real-time response does not match the simulation model and review must be performed. Please provide a response with a change for the model or a technical basis for continued use of the existing model within 90 calendar days. The response should be provided with insert PC/TP database name or to e-mail address here.

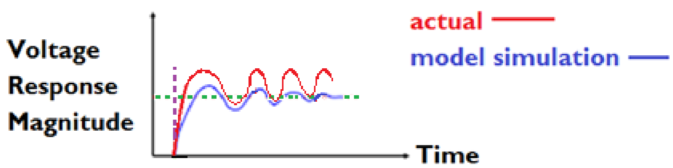


Figure 1 – Actual vs. Simulated Model Response on date(s) of event(s) – *Note Use detailed actual response diagrams for dynamics per Attachment 1 in MOD-032-1 or describe in detail power flow anomalies*

If I can provide any additional detail for this request, please contact me via e-mail at insert e-mail address here or phone at insert phone number here.

Sincerely,

Engineer /s/

Title
PC

Appendix F –Individual Company approaches for meeting MOD-033-1

Company A, Approach to MOD-033-1

Overall, COMPANY A approach is consistent with this NATF Reference Document. For requirement R1.1, COMPANY A selects a planning model case that is as close as possible to the real-time conditions under review. COMPANY A then uses an automated process to adjust a planning model case to simulate matching real-time conditions. Engineers use software to make changes to generation dispatch, accounts for line outages, transformer tap position, switch shunt device status along with position and phase angle regulator status. Load is also adjusted to values consistent with EMS and a sensitivity preformed to compare results without load adjustment in the original planning case (e.g. only matching EMS MW total not changing load dispatch and power factor in the planning model case) to adjusted values consistent with EMS. This approach identifies possible discrepancies in load assumptions.

During the software-testing phase, engineers opened and closed all elements or dispatched generation to a value that was easy to observe. For example, all generation might be set to a value like 1.99 MW and then .idv files produced with the software were applied to change the generator dispatch. It was easy to then spot when a generator didn't change status correctly, for example generators that were known to be dispatched at over 20 MW from real-time EMS were easily found if the planning model case showed 1.99 MW after attempting to change dispatch. Spreadsheets were used to compare EMS cases with simulation cases before adjustment and simulation cases after adjustment for each element that was changed.

For requirement R1.2, COMPANY A selected several local dynamic events for analysis. Using the software described in R1.1, device status is configured to be consistent with conditions measured with EMS just prior to the event. For the simulation, the triggering event is replicated and conditions found in the simulation are compared to real-time PMU or DDR plots. COMPANY A compares real-time event data with simulations using the planning model case for a multiple substation locations within its footprint.

All information from R1.1 and R1.2 testing and comparisons is saved in a SharePoint file and a logbook is used to record issues that are being reviewed based on the MOD-033 analysis. Several issues with load distribution assumptions and dedicated loads are being investigated at the time of this writing.

For requirement R1.3 guidelines to determine unacceptable differences, COMPANY A refers to Topic 5 in this NATF Reference Document. For steady-state comparisons, COMPANY A compares voltage and flows at interfaces and on select 345 kV facilities. COMPANY A assembles a diverse team that includes Management and SMEs to review dynamic event comparisons and determine if the results are acceptable.

For requirement R1.4 guidelines to resolve unacceptable differences, COMPANY A also refers to this NATF Reference Document and Topic 6. COMPANY A is registered as a TP as well as a PC so it can make requests under MOD-026-1 and MOD-027-1 as a TP in addition to MOD-032-1 as a PC.

Regarding Requirement R2 and obtaining actual system behavior data, COMPANY A is also a TOP and an RC. Many engineers have access to EMS, PMU data and other real-time data sources as well as simulation tools on their PC desktop. COMPANY A may request fault impedance, duration and distance information and other additionally available information regarding events from the Transmission Owner/Transmission Operators where the initiating fault occurred.

Company B, Approach to MOD-033-1

The process COMPANY B uses is based on NATF and WECC Guidelines for MOD-33-1 Model Validation.

Selection of Events

A WECC MVWG task force has been created to review various wide area disturbance events in WECC and select those disturbances which will be best suited for validation. COMPANY B typically uses one of those events unless the events did not produce an adequate disturbance in the company area. The same event is used for both the steady state and dynamic model validation. Conditions just prior to event are used for steady state model validation and event performance is used for dynamic model validation.

Steady-state Model Validation

Once an event has been selected, state estimator, SCADA and PMU data for the system and time being studied are acquired. The WECC guideline document describes the process used in selecting a planning case and assembling the case for model validation. The main intent behind validation of a steady-state model is to compare various parameters (e.g. bus voltages, real and reactive power flow on system elements and paths, generator dispatch, phase shifter settings, etc.) from the real-time steady state model to the same parameters in the steady state power flow created for this effort.

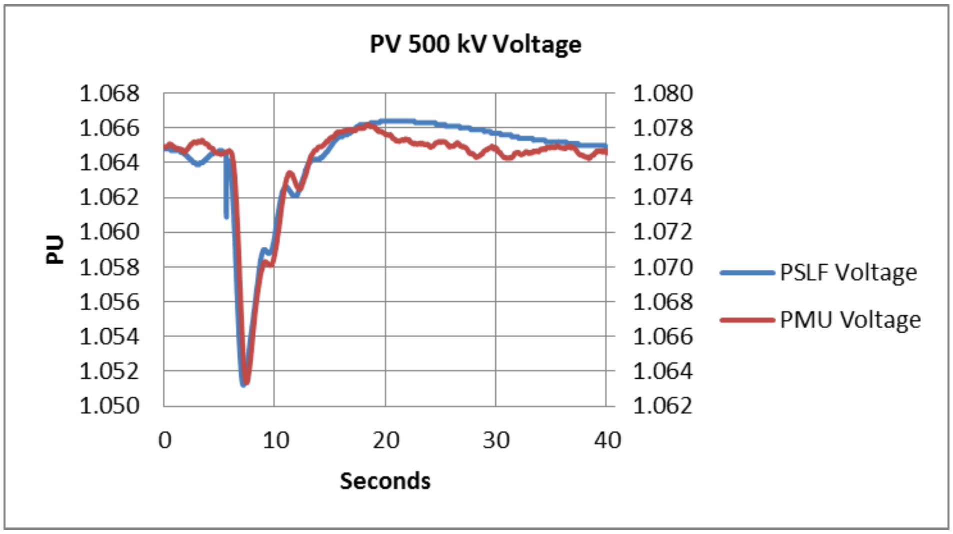
Initial validation work is done at the WECC level. This requires input from various entities and tuning the case until a satisfactory level of correlation is obtained. Once the validated effort at the WECC level is complete, WECC posts the steady state power flow and the dynamic file on their website. COMPANY B further tunes the case, as necessary, to provide an improved match of the parameters such as line flows and bus voltages in the COMPANY B area.

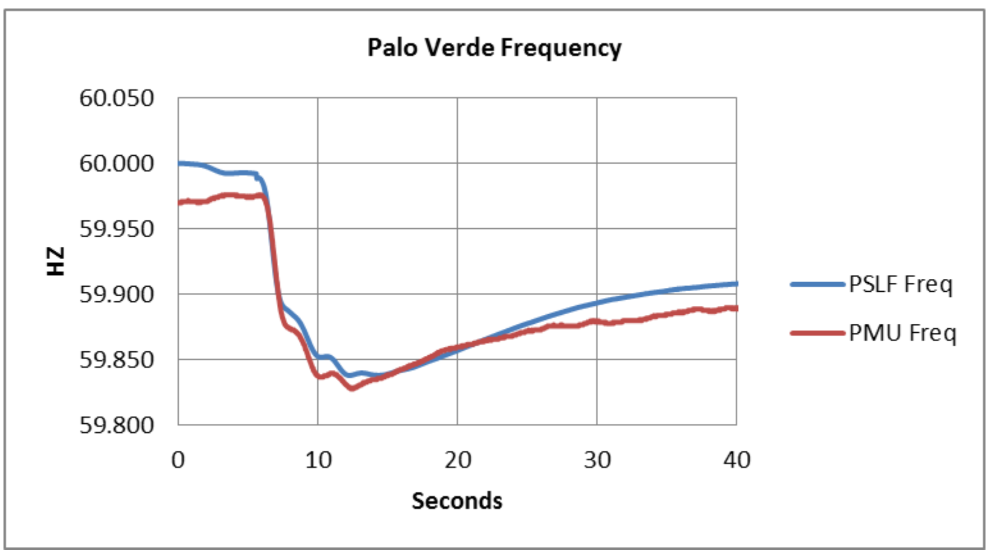
Dynamic Model Validation

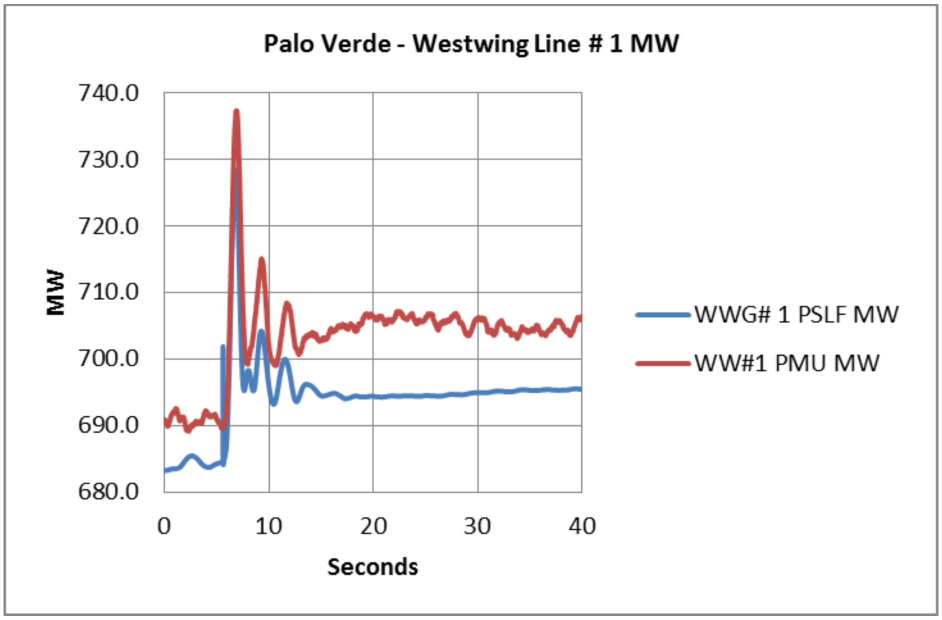
Once the steady state validation is complete, the dynamic simulation is run to compare the dynamic response of selected variables in the system. The buses are judiciously selected among the various buses where PMU data is available. PMU data is available for most 500 kV buses, 345 kV buses and selected 230 kV buses.

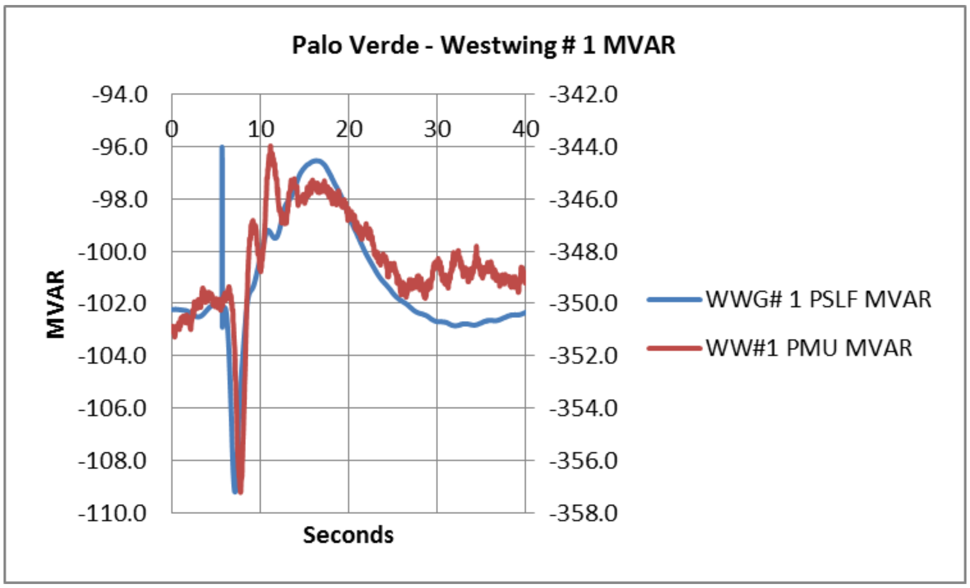
The simulated and measured response is plotted on the same plot to be able to compare the dynamic response and make an engineering judgment as to whether the correlation is reasonable.

Below is some example of correlation that was found to be satisfactory.

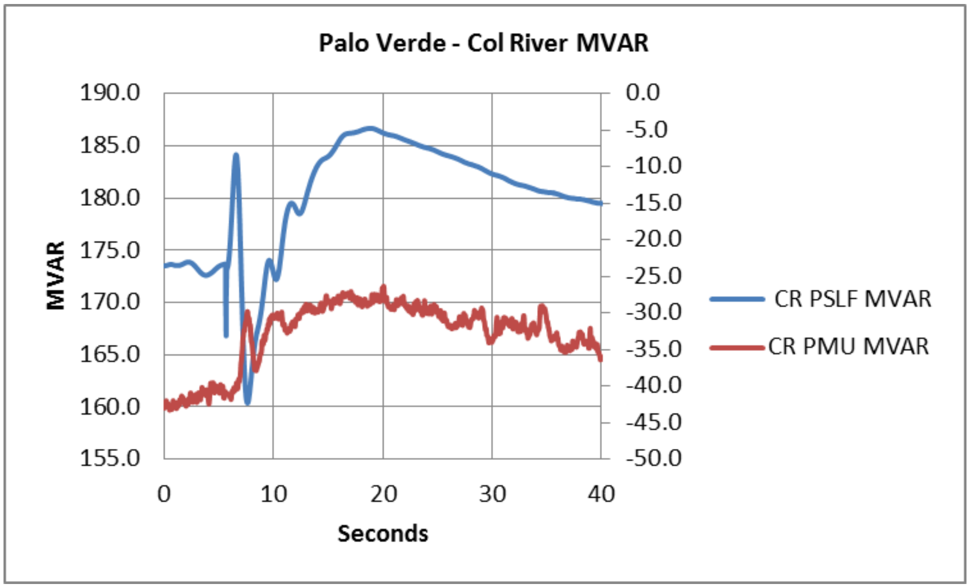





Palo Verde - Westwing Line # 1 MW
740.0
730.0
720.0
710.0
700.0
690.0
680.0
MW
0
10
20
30
40
Seconds
WWG# 1 PSLF MW
WW#1 PMU MW


Palo Verde - Westwing # 1 MVAR
-94.0
-96.0
-98.0
-100.0
-102.0
-104.0
-106.0
-108.0
-110.0
MVAR
0
10
20
30
40
-342.0
-344.0
-346.0
-348.0
-350.0
-352.0
-354.0
-356.0
-358.0
Seconds
WWG# 1 PSLF MVAR
WW#1 PMU MVAR

The dynamic correlation at certain buses may not come out satisfactorily. This could be due to various reasons including PMU calibration. Below is an example of unsatisfactory correlation. When the correlation is unsatisfactory, NATF and WECC guidelines are used to find the reason for poor correlation and appropriate steps are taken to resolve the discrepancy.



Company C, Approach to MOD-033-1

It is crucial that the transmission system models within the Planning Coordinator's portion of the system used in the planning process are as accurate as possible to provide a basis for power flow and stability studies. COMPANY C's approach on planning power flow model validation has been obtaining a snapshot of system conditions from a crucial load level, e.g., Summer Peak state estimator (or EMS) case, and making modifications based on the real-world data to a similar load level planning power flow case. The key real-world system data includes:

- Generation status (MW) and transmission system voltage on the high side of the GSU
- Loads MW and Mvar (or load power factor)
- Switched Shunts status and Mvar
- Area interchange MW and Mvar
- Major transmission elements status
- Voltages at transmission transformers with LTC

The changes listed above may not be changed all at the same time to avoid any power flow solution issues. Once these changes are implemented in the planning case, the following key quantities are compared:

- Generator (including SVC) Mvar outputs for major generating units
- Voltages at major transmission buses
- MW and Mvar flows on major transmission elements

The guidelines developed to determine the acceptance of the power flow results should be meaningful for the Planning Coordinator's system and should not be interconnection-wide.

For dynamic system model validation, a dynamic local event has to occur and disturbance data recordings from the nearby recording devices need to be available. The following dynamic local events are considered to the extent that proper disturbance monitoring/recording data is available:

- Fault events on the transmission elements
- Transmission line switching (including opening and closing) events without a fault
- Generating unit(s) tripping or local oscillation events

For dynamic system model validation using a dynamic local event, a dynamics ready planning power flow case is prepared by following the process described above. Additionally, to the extent that it is available, the sequence of the event and the disturbance data recordings related to the event are obtained. A dynamic simulation of the event is performed and the results from the simulation are compared to the actual event recording to determine the acceptance of the dynamic system model for the PC's portion of the system (Reference Figures 3 (a) and 3 (b)). The quantities are compared include:

- Voltage transient/oscillations at major transmission buses near the dynamic local event where disturbance data recordings are available
- MW and Mvar on generating facilities/units and major transmission elements near the dynamic local event where disturbance data recordings are available
- Frequency (for frequency excursion events)

The dynamic comparison to determine if the match between the simulated response and the actual equipment response is acceptable is based on visual inspection.

When resolving any unacceptable differences in performance identified under Part 1.3 in the standard, in addition to the recommended steps in Topic 6 of this document, the following is considered:

- If the actual system response is measured at or near a generating facility with more than one unit in service during the dynamic local event, the actual units in service at the time of the event and the generator related dynamic modeling data should be closely reviewed. The PSS status for units nearby could play a key role on this effort. This could lead to outreach to unit owners as detailed in Topic 6 of this document.
- If the actual system response is measured at or near a FACTS device, the dynamic modeling data of such a FACTS device should be reviewed.

Company D, Approach to MOD-033-1

Steady-state Model Validation

The real-time data COMPANY D uses is a snapshot case from the state estimator during summer peak time. The same-year summer peak planning model is compared with the EMS snapshot case. COMPANY D implements a decoupled comparison process, which is to compare then real power flow first, and then compare the voltage. Since both processes are similar, this decoupling helps separate the real and reactive issues to find the causes of the performance differences more efficiently. All 230 KV-and-above line real power flows and critical bus voltages between two cases are then compared. Significant differences are reconciled through an iterative process until either all the major line flow and bus voltage are within acceptable threshold or there are explainable reasons for the differences. All the network corrections identified during this process are applied to all the current and future EMS/Planning models. The general process is demonstrated in the below diagram.

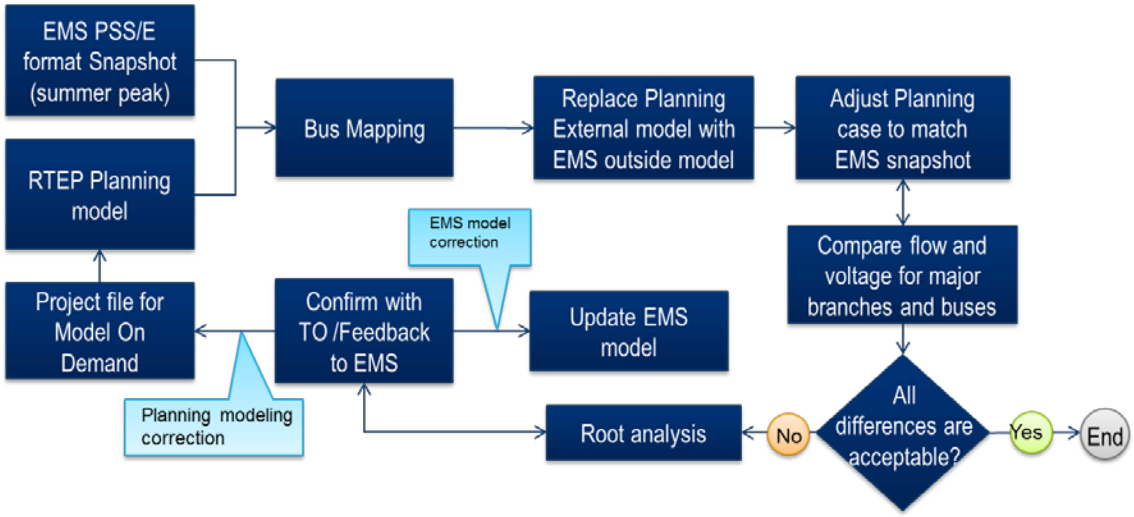


Figure 1 COMPANY D Steady-state Model Validation Process

The goal is to align real power flow difference on all the 500 kV lines between EMS case and planning case within a reasonable/acceptable range. This means the differences need to be either under a certain megawatt threshold (e.g. 100 MW) or otherwise justified. To achieve this, COMPANY D adopts a bottom-up process. All the significant real power flow differences on 230 kV and above transmission lines are listed. The root cause analysis starts from the lower voltage level. For 230 kV and 345 kV transmission facilities, a 50 MW threshold is applied at this stage. In the initial comparison, 161 500 kV and above lines are compared and nine of these have more than 100 MW flow difference. The cause of the significant difference falls into the following major categories: topology differences, missed local transmission outages, local generator dispatch, open/close bus tie during operations, line impedance, local loads, etc.

The following Figure 2 shows the 500kV and above lines real power comparison results before and after reconciliation.

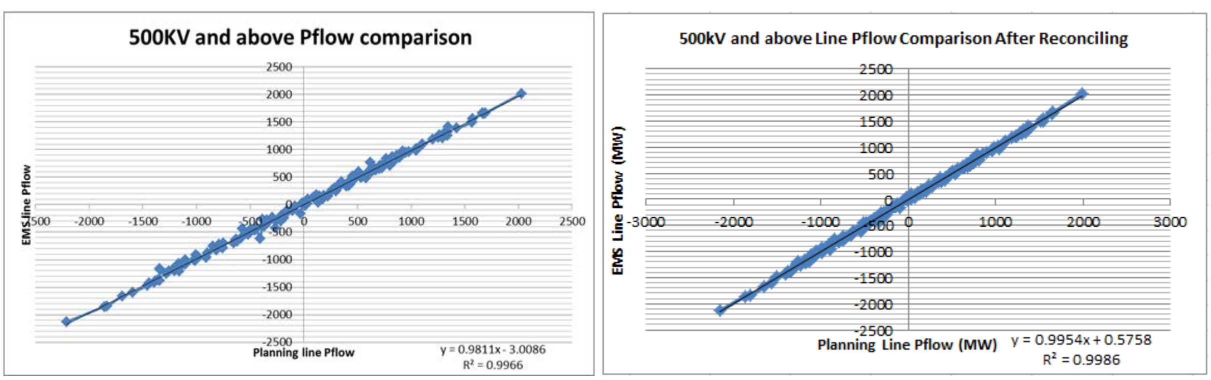


Figure 2 500kV and above lines real power flow comparison before and after reconciling

Dynamic Model Validation
COMPANY D dynamic model validation is classified into two categories based on a validation boundary: 1) area-level dynamic model validation and 2) plant-level (device) model validation. In the area level model validation, the aggregate performance of dynamic models in the area around a disturbance of interest is evaluated. General process of the area-level dynamic model validation is similar to that of NATF Guidelines for MOD-033 Model Validation. Full Eastern Interconnection Planning Model is used in the simulation but a reduced model including the study area and its neighboring areas can be used if necessary.

If measurement data from PMU/DFR is available at a plant or a dynamic device, a plant-level model validation is conducted using a reduced network model and the measurement data as a boundary condition. Once a dynamic event scenario is selected, the process of plant-level dynamic model validation is as follows: 1) measurement data preparation, 2) case creation and simulation, 3) performance evaluation.

Measurement Data Preparation

PMU/DFR data taken at either the generator terminal or the high side of GSU is preferred, since the validation problem can be simplified down to a plant level by using the measurement data as a boundary condition between the study plant and the external system. Currently, the sampling rate of PMUs in the COMPANY D footprint is 30Hz. A 30Hz sampling rate may not be high enough to validate some dynamic models, especially exciter models with small time constants given numerical issues such as oscillations. In this case, original measurement data needs to be resampled at a higher rate, using linear interpolation.

Case Creation and Simulation

A simplified power flow case is created through reduction of a comprehensive planning case. The study plant and associated network (up to a boundary bus where the PMU is installed) are extracted from the planning case. In order to feed measured input data into the boundary bus, a classical generator with large inertia is generally connected to the boundary via a zero impedance line.

Once measurement data is set and a study dynamics case is prepared, the dynamic simulation is conducted to generate model output for performance evaluation using commercially available dynamic simulation tools or COMPANY D internal model validation tool.

Performance Evaluation

The validity of dynamic model is assessed by comparing simulation results and measured data. Several dynamic performances can be reviewed including overshoot, rising time, oscillation frequency, damping ratio, phase and steady state. Engineering judgement and domain knowledge are crucial to validation since it is difficult to set clear performance metrics for validation. In this regard, collaboration with asset owners who have knowledge about plant- specific dynamic models can be very useful. If the discrepancy between the simulated model response and measurement data is substantially large, COMPANY D initiates a resolution process through MOD-026/027/032. Figures 3-5 show the examples of voltage, real and reactive powers comparison.

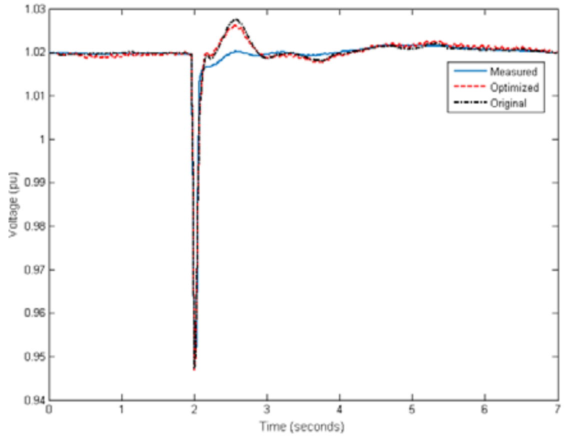


Figure 3 Example of voltage comparison

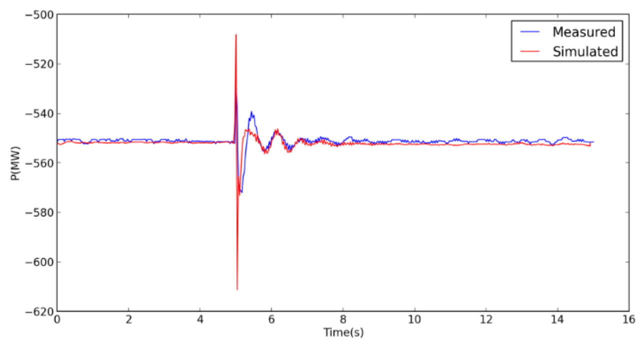


Figure 4 Example of real power comparison

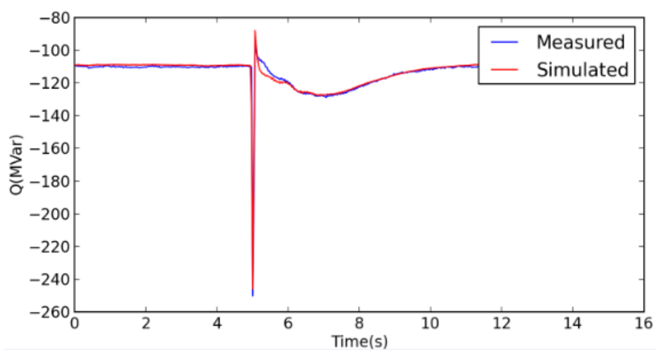


Figure 5 Example of reactive power comparison

Appendix G – MOD-033-1 Review Checklist

- For R1.1 steady state comparison or to set up the planning model before a dynamic event ensure equipment dispatch in the planning model matches real-time addressing:
  - ☐ Transmission/generation outages
  - ☐ Transmission topology changes
  - ☐ Area interchange
  - ☐ Generation dispatch
  - ☐ Generator scheduled voltage
  - ☐ Loads
  - ☐ Switched shunts status/position
  - ☐ Transformer tap positions (fixed and adjustable)
  - ☐ Power Electronic and Flexible AC Transmission System (FACTS) devices
  - ☐ Run the simulation and compare to real-time data from EMS or other source

- For R1.2 dynamic model to actual system response comparisons:
  - ☐ Select local or wide-area events
  - ☐ Ensure the event selected results in perturbation of the PC area
  - ☐ Obtain real-time data before and after the event (usually from SCADA or EMS)
  - ☐ Sources of real-time data during the event are likely to be DDRs or PMUs
  - ☐ Ensure that a no-disturbance simulation produces flat line results
  - ☐ Run the simulation and compare to DDR or PMU plots or other real-time data source

- R1.3 guidelines to determine whether differences are acceptable:
  - ☐ Use engineering judgment when reviewing power flow and dynamic simulation comparisons
  - ☐ Use the numerical guidelines provided in Table 1 to determine acceptable results for power flow comparisons on selected lines or interfaces
  - ☐ Compare side by side real-time and simulated event plots for dynamics
  - ☐ Apply engineering judgment when results do not match for dynamics.

- R1.4 guidelines to resolve unacceptable differences in performance
  - Check for inaccuracies that may be due to equipment set-up or calibration errors that cause inaccurate measurements
  - Address the appropriate standards listed below when it is necessary to request equipment owner model reviews:
    1. MOD-032-1 R3 general power flow element or dynamics differences (except load) as described in Attachment 1 unless covered by the MOD-026-1 or MOD-027-1.
    2. MOD-026-1 R3 and R5 for generator excitation system differences based on one or more events. Within the Eastern Interconnection, reviews can be for generators 20 MVA and above. See the applicability section of MOD-026-1 for further details (The request is actually made by the TP.)
    3. MOD-027-1 R3 for generator governor based on differences observed for three or more frequency events. Within the Eastern Interconnection, reviews can be for generators 100 MVA and above. See the applicability section of MOD-027-1 for further details. (The request is actually made by the TP.).
  - Include technical information showing the mismatch with requests to equipment owners including the appropriate number of event responses based on the requirements of the MOD standard listed above.

- R2 requests to Reliability Coordinators and Transmission Operators
  - Include date and time of the real-time data needed
  - Detail specific data needed such as PMU or DDR event recording, fault impedance, estimated distance from substations and fault clearing time
  - Indicate that the request is made for MOD-033-1 review and that information must be provided within 30 days of this written request per the standard.