

Unofficial Comment Form for Generator Verification (Project 2007-09)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the Second Posting of MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Project 2007-09). The electronic comment form must be completed by **August 1, 2011**.

[Project 2007-09 Generator Verification](#)

If you have questions please contact Stephen Crutchfield at Stephen.Crutchfield@nerc.net or by telephone at 609-651-9455.

Background Information

The purpose of Project 2007-09 - Generator Verification is:

- To ensure that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit's capabilities).
- To ensure that generator models accurately reflect the generator's capabilities and operating characteristics.

The standard drafting team (SDT) for Project 2007-09 Generator Verification based its work on two existing NERC Board approved standards:

- MOD-024-1 — Verification of Generator Gross and Net Real Power Capability.
- MOD-025-1 — Verification of Generator Gross and Net Reactive Power Capability.

And four draft standards developed by the Phase III & IV SDT that were field tested by four Regions from mid 2006 through mid 2007.

- PRC-019-1 — Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection
- PRC-024-1 — Generator Performance During Frequency and Voltage Excursions
- MOD-026-1 — Verification of Models and Data for Generator Excitation Control System Functions
- MOD-027-1 — Verification of Generator Unit Frequency Response

This is the second posting of standard MOD-026-1 Verification of Models and Data for Generator Excitation Control System Functions for industry review. It should be noted that the title of the standard has been changed from "Verification of Models and Data for Generator Excitation Control System Functions" to "Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions" in order to reflect the SDTs inclusion of plants with several small units, in large part to include Variable Energy

Resource plants (discussed in more detail below). The second posting of standard MOD-026-1 Verification of Models and Data for Generator Excitation Control System Functions was developed with consideration of industry response to questions that were posed as part of the Comment Form accompanying the first posting. This posting also includes the initial posting of standard MOD-027-1. Note for the same reason discussed for standard MOD-026-1, standard MOD-027-1 has been re-titled from "Verification of Generator Unit Frequency Response" to "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions". While there are a few differences between standards MOD-026-1 and MOD-027-1 as detailed below, there are also many similarities. The two standards are similar in both substance and style.

Standard MOD-026-1:

One of the major issues that the SDT presented to industry during the first posting was the functional entity "applicability". The SDT recognized that assigning responsibility to appropriate entities for a continent wide standard for verifying unit excitation system models would be difficult. In the first posting of the standard, the SDT selected the Generator Operator to be the appropriate entity to be responsible for verifying the model. However, industry feedback from the first posting indicated that the majority of industry participants felt that the Generator Owner was the appropriate entity to assign responsibility. The SDT also consulted with the NERC Functional Model Working Group (FMWG) which felt that the Generator Owner was the appropriate entity to assign model verification responsibility. Therefore, in this second posting of standard MOD-026-1, the responsibility for model verification has been assigned to the Generator Owner. As such, it is up to the Generator Owner and Generator Operator to define contractual arrangements needed to comply with the requirements of this standard.

A significant change incorporated into the second posting of this standard is a proposed process where the Planning Coordinator can request a review of an excitation control system model. Many of the affirmative responses from industry qualified their answer by stating that the process needs to be well defined. As such, the new Requirement (R5) requires the Planning Coordinator to supply technical justification for the request. If upon receipt of this notification the Generator Owner has revised excitation control system model data, then the Generator Owner can supply that data to the Planning Coordinator. An example might be the discovery of unit specific "as-commissioned" manufacturer data which would be more accurate than generic manufacturer data. If better data is not available, or does not address the Planning Coordinator's dynamic modeling and stability performance needs, then the Planning Coordinator can request the Generator Owner to review the excitation control system model and provide revised data. Since the Generator Owner has already provided updated data to the degree possible without verifying the model, then the Generator Owner would be required to verify the model within the time frame specified in the Periodicity Table (one year to obtain a recorded response of a voltage excursion and submission of the model within 180 days after obtaining the recorded response).

The SDT also asked industry several questions pertaining to the extent facilities are to be verified, including periodicity for model verification. As a baseline, the SDT recognized that the excitation system models and model data are already collected through the processes identified in standards MOD-012 and MOD-013. This information, with few exceptions, already establishes a quality dynamics database. However, as confirmed through field testing, performing verification activities specified in the draft standard will improve the accuracy of exciter models used in dynamic simulation. Major themes expressed by industry and subsequent action taken by the SDT include:

1. The present draft of the standard maintains a base Applicability requiring verification of excitation systems associated with 80% or greater of the connected MVA per Interconnection (refer to Item 5 below). The present draft of the standard does clarify that the connected MVA threshold for plants is to include units connected at the same point of interconnection. For example, if a plant site has generators interconnected to two different transmission voltage levels, the MVA threshold would be applied based on the cumulative MVA of the generators interconnected at each transmission voltage level.
2. The majority of industry agreed with the 5% capacity factor threshold. The application of the capacity factor threshold has been clarified in the new Periodicity Table.
3. The majority of industry agreed with the philosophy of allowing excitation control system verification for a single unit to satisfy compliance for other units if certain conditions are met (such as having the same MVA rating, having identical applicable components and settings, and being sited at the same physical location); which remain unchanged in the present draft of the standard.
4. Based on industry comments and technical justification regarding the nameplate MVA of steam units for existing Combined Cycle plant technology, the SDT raised the threshold MVA nameplate rating from ≤ 250 MVA to ≤ 350 MVA.
5. Industry agreed with the general ten year periodicity timeframe proposed. It was pointed out to the SDT that periodicity alone did not constitute a standalone reliability requirement. Therefore, R1 from the previous draft of the standard has been removed and replaced with a Periodicity Table. The Periodicity Table provides the base ten year applicability timeframe for collecting data needed to perform the verification, and adds an additional year to perform the verification analysis. The Periodicity Table also addresses scenarios which could require additional testing and subsequent model re-verification. The Periodicity Table will enable Generator Owners to quickly determine required retest dates for model verification.
6. Several industry responders asked if the standard was applicable to wind generation. As detailed in the Response to Comments document posted on the NERC website, the Applicability section MVA threshold in the first posting of standard MOD-026 resulted in wind powered units not being subject to this standard because individual wind units are not rated greater than 20 MVA. However, since there are an increasing number of wind farms with significantly larger aggregate MVA, their impact on the reliability of the Bulk Electric System cannot be ignored; otherwise, a reliability gap would exist. Therefore, as requested by industry, the SDT discussed the possibility of requiring verification of dynamic models that represent the aggregate of numerous small units and necessary auxiliary equipment required of the technology. This could include plant dynamic voltage control and reactive support of all the units and auxiliary equipment (such as individual WTG response, plant-wide volt/var controller response, and response from separate volt/var regulation devices contained in the plant such as SVC/STATCOM/Synchronous Condenser) contained in any technology generation plant, including a wind farm (plant), that exceeds the aggregate nameplate MVA threshold specified. There are dynamic models that adequately replicate performance for some wind units today. However, there are many existing wind units which do not have publicly available models supplied by the Original Equipment Manufacturer. Generic wind models (i.e., type I, II, III and IV) are in various stages of development. Also, there are ongoing efforts involving Regional Entities and manufactures to close any large gaps that may exist in current generic models. Thus, the SDT believes that generic wind farm

(plant) models will reach an appropriate state of maturity for establishing boundary conditions in Bulk Electric System Studies in advance of the eventual effective date of this standard. Therefore, to mitigate this reliability gap, the Applicability section has been expanded in the second posting of the standard to include a significant MVA percentage of all generation of all technologies. Specifically, based on review of in-service wind farm plant data, that includes approximately 80% of the wind farm plant MVA capacity in each Interconnection, the MVA threshold for plants was decreased from 200 MVA to 100 MVA for the Eastern and Quebec Interconnections, 150 to 75 MVA for the WECC Interconnection, and from 100 to 75 MVA for the ERCOT Interconnection (note – reducing the MVA threshold for plants in ERCOT any further would have exceeded the NERC Compliance Registry criteria. The 75 MVA plant threshold specified includes more than 80% of the wind farms in ERCOT). Additionally, the language makes clear that plant units less than 20 MVA should be verified in aggregate when possible.

The SDT drafted the first posting of the standard with minimal technical specificity so that either traditional staged testing, or ambient monitoring and other future techniques could be refined and utilized while still satisfying the Requirements. The SDT drafted a standard that concentrates on stating “what is required” but without stating “how to accomplish what is required”, with peer review processes. Based on industry comments, the present draft of the standard maintains this same philosophy.

Several industry responders pointed out that the first posting version of the draft standard arguably contained non-reliability related requirements, and/or the chronological and procedural style resulted in a cumbersome document that was hard to follow. With this feedback, the SDT refined the standard to contain only reliability related requirements. This effort resulted in the creation of a Periodicity Table which is an attachment to the draft standard but is not a standalone requirement. Also, activities that are expected to occur infrequently, such as the “peer review” process, have been incorporated into Requirement Parts that are not intermingled with the 10 year periodic model verification base tasks. The SDT also combined all information the Generator Owner has to provide the Transmission Planner following successful model verification into a single section (reference requirement R2, Parts 2.1.1 through 2.1.6 of the revised standard). This information also includes the generator model data used in the excitation control system verification process however, the SDT stopped short of requiring generator model data verification. The majority of industry comments indicated a separate SAR would be required for a generator model verification standard.

The SDT discussed if standard MOD-026-1 should also include verification of excitation control systems of synchronous condensers¹. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of Synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. There is no peer review requirements incorporated into standard MOD-025 which address steady state modeling thus, the inclusion of synchronous condensers in

¹ Note this does not include hydro generators which can operate in a “synchronous condenser” mode. If this mode of operation is expected, then the model should reflect this operating state.

standard MOD-025 is a better fit. Also, if Transmission Owners decide to pay for synchronous condenser installation and maintenance, which by its very nature does not generate Real Power as a source of revenue, then by default the apparatus is installed for dynamic voltage support; most likely to extend a dynamic voltage security limit. Therefore, the Transmission Owner should be highly motivated to understand and model synchronous condenser dynamic behavior. Therefore, the SDT decided that if there is a need to develop a Reliability Standard to model the expected dynamic behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include Synchronous Condensers along with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR.

The first posting of the draft standard proposed an implementation plan requiring 10% of a Generator Owner's applicable units to be verified within two years following standard approval, 50% within six years following standard approval, and 100% within eleven years following standard approval. Concern was raised regarding the start up time to establish processes that this standard would require. For this concern, the SDT decided to extend the timeframe following standard approval for the first set of models required to be verified from "after 2 years of regulatory approval, 10% of its applicable units per Interconnection on a MVA basis" to "...four years following applicable regulatory approval....Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R2." In addition to allowing entities additional start up time to develop this expertise, the new timeline allows traditional staged testing to be performed concurrent with the planned maintenance outage schedule. The language "being compliant with R1" means that suitable voltage excursion data has to be collected per the Periodicity Table. Entities actually have an additional year to analyze the voltage excursion data to verify the model and communicate the results to the Transmission Planner. Finally, the SDT has accepted the recommendation to allow verification of excitation system model(s) with established Regional Entity procedures and guidelines for demonstrating compliance with this new standard if the verification is completed within 10 years of standard approval (reference the proposed Implementation Plan).

Differences also exist between MOD-026-1 and MOD-027-1:

- 1) The implementation plan for standard MOD-027-1 is structured to recognize that Generator Owners will either need to install equipment to record the real power output of units during an appropriate frequency excursion or modify the existing recording equipment (such as frequency triggers, recording time, etc.). The proposed implementation plan specifies compliance with R2 at intervals of 25% of applicable units per Interconnection on a MVA basis three years after the effective date, 50% at five years, 75% at seven years, and 100% at nine years. Compliance with R2 as per the Periodicity Table (Table 1), means that beginning on the implementation date, the Generator Owner has 10 years to obtain an appropriate recorded response, and 2 years after obtaining the appropriate recorded response to verify the model (see Item 4 below that discusses exceptions to the aforementioned timeframe).
- 2) Like the draft standard for verification of excitation control system models, this draft standard allows for both staged tests and for ambient monitoring. However, the SDT expects that the majority of turbine/governor and load control functions will be verified through ambient monitoring. To ensure the impact of outer loop controls is captured and replicated in the model, the standard allows

staged tests where a frequency reference change is applied if the unit is on-line. This type of test is not common. Many units do not have a frequency reference change input where such a signal can be applied. Therefore, the SDT recognized that the Generator Owner's opportunity to verify that the predicted model response matches the recorded response for an appropriate system frequency excursion will often be dependent on its unit being on-line and in an operating state to respond to the system frequency excursion when it occurs. The basis for this strategy is:

- a. Large economical units have a higher probability of being on-line in a proper operating state to experience a frequency excursion requiring model verification.
 - b. Units which are not on-line or not in a proper operating state will not help arrest the frequency excursion. Even if this is not the case, it is better to experience an event for model verification as opposed to relying on a survey that may be inaccurate.
- 3) In the current draft of MOD-026, the Generator Owner has one year from the capture of a voltage excursion to verify the excitation control system model. This timeframe is based on the SDT's belief that the majority of exciters will be verified using a staged test; and if ambient monitoring is utilized, there will be frequent naturally occurring transmission system voltage excursions. Since the SDT anticipates that the majority of the units' turbine/governor and load control models will be verified utilizing ambient monitoring, it is recognized that it is appropriate to give the Generator Owner time to retrieve captured data. Unlike ambient voltage excursion data needed for excitation control system model verification, the unit must be in an operating state that would allow the unit to respond to the frequency excursion. Also, it is likely that the number of acceptable frequency excursions (from a compliance perspective) will be significantly fewer than the number of acceptable voltage excursions that would occur for model verification. Therefore, the SDT decided to allow the Generator Owner two years for verifying the model. This timeframe allows adequate time to a) realize the event has occurred while the unit was in the proper operating state, and b) to verify the model. This timeframe will also assist the Generator Owner with planning contractor, budget and schedule support if activities are outsourced.
- 4) A unit has to be on-line and in the proper operating state during a frequency excursion in order to capture an effective real power response for model verification. Therefore, the standard provides time for the Generator Owner to capture and record a response requiring verification, even if it takes longer than ten years to do so. This language, which is contained in the Periodicity Table, is specifically crafted so that extension of the ten year periodicity cycle will only happen if a frequency excursion does not occur with the unit on-line and in the proper operating state. Therefore, the lack of installed and operating recording equipment during a frequency excursion is not a valid excuse for obtaining a ten year timeframe extension.
- 5) Industry experience has shown that a unit's real power response to a system frequency excursion could be different from one event to the next. Reasons include different unit load levels, prime mover control conditions, operator control mode, and magnitude of the frequency deviation. By contrast, excitation control

system responses to system voltage excursions are much more consistent. Therefore, the main model verification requirement (R2 Part 2.1.1) calls for the turbine/governor and load control model to be "compared to" the recorded response of actual equipment whereas in standard MOD-026-1, the wording is "matches".

- 6) In standard MOD-026-1 R3 there is a process where a Transmission Planner can make a written request, including evidence that the excitation control system (or plant volt/var) model response did not match an actual recorded response, to the Generator Owner which essentially requires the Generator Owner to review the model. While there is similar language in standard MOD-027-1 R3, there is the additional stipulation that the Transmission Planner must include supporting evidence of instances where model response did not match an actual recorded response. The reason for this is that the governor response is not consistent enough from one frequency excursion event to the next for several reasons, such as the operating condition of the plant, ambient temperature, the number of coal pulverizers on line, the pre-contingency MW output of the unit, etc. In fact, while the fundamental requirement for verifying the model once every ten years can be satisfied by taking into account only a single frequency excursion, it is strongly recommended that model verification be performed taking into account multiple frequency excursions (if available and assuming the unit was in a proper operating state as required for model verification).
- 7) The activity specified in Requirement R4 is similar to draft standard MOD-026-1 Requirement, R4 which lists the evidence of compliance that the Generator Owner must maintain whenever certain activities occur that alter the equipment response; resulting in providing either revised model data or re-verifying the model. Unlike excitation control systems, there are many control parameters associated with the turbine/governor and load control system which will not impact equipment performance that is required to be replicated in the dynamic model. Thus, standard MOD-027-1 Requirement R4 is specifically crafted to only include setting changes for droop, and/or dead band, and/or load control mode. Since it is likely that many Generator Owners will rely on the expertise of consultants to make the determination of how modifications to droop, dead band, and/or load control mode translate into modified model parameter values, a time period of 180 days is proposed.
- 8) In MOD-026-1, the SDT is proposing a process where the Planning Coordinator can request a review of an excitation control system model for a unit not specified in the standard Applicability section. The new MOD-026-1 Requirement (R5) was added in response to industry comments. It requires the Planning Coordinator to supply technical justification that demonstrates either a) the unit affects a stability limit, or b) the simulated unit response does not match a measured unit response (most likely captured during a system disturbance event). However, this process is not being proposed for MOD-027-1. It is extremely unlikely that the turbine/governor and load control or active power/frequency control system will contribute to a stability limit. Also, as already discussed (Item 6), governor response is not consistent from one frequency excursion event to the next. Therefore, the SDT did not feel that such a Requirement in MOD-027-1 was necessary.

- 9) There is no need for the Transmission Planner to provide the generator MVA base when providing models for turbine/governor and load control or active power/frequency control systems. The MVA base associated with the generator model is already required to be provided per Requirement R1 of standard MOD-026. The MW base information is reflective of turbine capability and is provided as one of the turbine/governor and load control model data parameters specified. The MW base information, depending on the dynamic simulation software provider model requirements, will either be in the form of an actual MW value or a per unit MW value; with the base being the MVA value that is used in the generator steady state model.
- 10) The Generation Verification SDT is closely following and coordinating with the Frequency Response SDT. It is hoped that the Frequency Response SDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, though the Frequency Response SDT has discussed this concept and is investigating the use of a tool to help facilitate the identification of appropriate frequency excursions, the process is still evolving. As an interim step, the Generation Verification SDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine/governor and load control functions for the purpose of model verification and b) would be expected to occur 15 times a year or more. If by chance a process identifying frequency excursions that can be utilized in support of standard MOD-027-1 requirements is not developed by the Frequency Response SDT, then such a process will have to be proposed for future revision to standard MOD-027-1 by the Generation Verification SDT.

Compliance Elements for MOD-026-1:

The SDT added Compliance Elements to the second posting of the standard. The VRF's for Requirements R1-R6 are all designated as low risk. All of these Requirements provide for an update of dynamic modeling data for an existing unit. Violation of these requirements would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system, which is consistent with the low risk level guidelines.

The VSLs for Requirement R2 was selected using the metric of "Requirements with Parts that Contribute Equally to the Requirement". All of the items listed in Requirement R2 are required for successful model verification. The remaining VSLs were selected using the metric of "Increments for Tardiness". The Requirements cover activities that are not typical such as peer reviews and instances where there is concern that the model does not reliably reflect actual equipment performance. As such, timeliness of communications is paramount.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The Applicability section of MOD-026 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability?

Yes

No

Comments:

2. The current version of the MOD-026 standard has been re-formatted so that it would be more concise and contain only reliability related requirements. Do you agree there are no omissions from the prior draft due to the re-formatting of the standard?

Yes

No

Comments:

3. The SDT discussed if MOD-026-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR.

Do you agree with the proposal to not include the verification of synchronous condensers in MOD-026-1?

Yes

No

Comments: Synchronous condensers are installed at locations where they are specifically needed for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.

4. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain.

Yes

No

Comments: We have a number of questions and concerns as follows:

- It is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test?
- If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data?
- We have concern about whether this Standard is cost effective for the industry. The transient stability dynamic modeling for excitation control was traditionally developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts required by this standard are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
- MOD-026 does not account appropriately for the differences between distributed generation and single shaft generation. Aggregate generation that do not have a common excitation and regulator control system (such as wind farms) may pose serious difficulties in meeting system disturbance and / or staged testing. A staged test can be performed for a single shaft unit. However, wind farms may not have a centralized plant or wind farm voltage controller. If that isn't the case, entities may be forced to actually shock the BES to force a disturbance large enough to force a wind farm response. If this is true, then exceptions need to be made.
- In addition, there are concerns about the technical development and accuracy of current wind farm models. It is not certain that all manufacturers have fully developed all of the control system models necessary to meet these standards. Type III and Type IV PSS/E generic standard models have all been benchmarked. What has not been included in these models are the wind farm park voltage controllers. While local turbine model controllers will dominate the short term response, the longer term park voltage controls are not represented. Therefore if the models aren't available, then model traces can't accurately match reality. Older wind farms will not have appropriate models. In short, the state of wind farm models hasn't completely developed to match wind farms and specific exemptions for wind farms need to be added to the standard at a minimum.