Individual or group. (46 Responses)
Name (31 Responses)
Organization (31 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (46 Responses)
Question 1 (31 Responses)
Question 1 Comments (41 Responses)
Question 2 (31 Responses)
Question 2 Comments (41 Responses)
Question 3 (0 Responses)
Question 3 Comments (41 Responses)

Individual
Jim Watson
Dynegy
Yes
Yes
Some smaller Generator Owners have little experience in this type of testing. If possible, it is suggested more detail be placed in Attachment 1 regarding what constitutes an acceptable test, i.e., template.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
We would suggest that there be something added to give those GO’s who have not modified their plants to be able to opt out of the re-verification. There is a concern that the updated data would be at least a year out of step with the development of the ERAG model in the eastern interconnect.
Group
Northeast Power Coordinating Council
Guy Zito
Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Tennessee Valley Authority
Brandy Spraker
Yes
No
Attachment 1, Row Number 5, Recommend deleting “at the same physical location” from the Verification condition. The first condition is recommended to read “Existing applicable unit that is equivalent to another unit(s),”

Justification is that if a GO has units that are equivalent and meet the “sister” criteria, the standard does not need to be restricted to the same physical location. The GO identical equipment at different physical locations are still equivalent.
Step 4.2.3, Recommend adding “in” to the requirement to read “Generation in the ERCOT Interconnection ...” Justification is to be consistent with similar steps 4.2.1 and 4.2.2.
Individual
Cristina Papuc
TransAlta Centralia Generation LLC
Yes
Yes
N/A
Individual
Lynn schmidt
NIPSCO
Verification requirements would be burdensome, e.g., model response by a load rejection test or comparison with a system frequency excursion may be of only limited value. Another basic problem with this standard is the unnecessary back and forth between generation owners and transmission planners in the data development and collection. This standard could be greatly simplified for all involved parties with reporting requirements similar to MOD-025 where the generation owner provides information to the transmission planner upon the installation of new equipment or the modification of existing equipment. Given the above, Transmission Planning recommends a vote against this standard in its present form.
Individual
Nazra Gladu
Manitoba Hydro
Yes
None.
Yes
None.
R1 - The text would be more clear if rewritten to read ‘Within 90 calendar days of receiving a written request, each Transmission Owner shall provide to its requesting Generator Owner:’ 4.2 - The language immediately preceding the bullets is unclear: ‘that meet the following’ should perhaps be rewritten as ‘provided they meet the following’. Effective Date Section 5.1 - Manitoba Hydro recommends changing the “R6” to “R5” because there is no “R6” in the standard. General Comment - Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?
Group
pacificorp
ryan millard
Yes
Yes
Group
Bonneville Power Administration
Chris Higgins
Yes

Yes
Individual
Winnie Holden
PSEG
Yes
Yes
We voted “Negative” on this standard the reasons shown below: This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1. 1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a “team” with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as “applicable facilities,” while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments: “The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.” The SDT responded as follows: “The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.” In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.” PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.” We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon. This SECOND COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-024-1. 2.DATA SHARING POLICY: For all of the MOD standards in this, only Transmission Planners are the recipient of the data developed. We asked that the standard require that the TP be required to share the data with others. The response we received is that the Functional Model requires the TP to share data with the TOP. Unfortunately, the Functional Model is unenforceable. We note that in PRC-024-1 R6 requires the GO to share its data with the RC, PC, TOP, and TO, upon request. Unless the same data is shared across all “modelers,” the result will be outdated data in someone’s model, which can have a bad result. The team should have one broad “data sharing” policy in the three MOD standards and PRC-024-1. Since the TP receives data in three of the standards, we suggest this language or similar language: The GO shall provide data to its TP within 60 days of its development [describe the data]. The TP shall provide the same data to any RC, PC, TP, or TOP within 60 days of receiving a request for it.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)
Yes

Yes
Ingleside Cogeneration LP agrees that the explanation of the periodicity requirements are an improvement over previous versions.
Ingleside Cogeneration LP agrees that the ability for Transmission Planners to effectively model and simulate actual system response to frequency transients can lead to reliability improvements. In addition, the technical language used in the latest version of MOD-027-1 has been refined to an acceptable point in our view. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring tests (R2) must contain language that focuses on the strength of the validation process – not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed – even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
ATC recommends the following changes: 1. For Requirement 5, ATC recommends replacing the wording at the end of the requirement "that includes the following;" with "that includes how any of the following criteria are not met:" because the existing wording does not express that the criteria are not met when the model is not usable. 2. Attachment 1, Row 7, Verification Condition column – ATC agrees with the STD intention that base load units should be exempt because they are "not responsive to frequency excursion events". However, this insinuation of base load units is too vague. Therefore, ATC recommends additional wording to read "New or existing base loaded units are normally not responsive to a frequency excursion event". This makes it abundantly clear that this condition normally applies to base loaded units.
Individual
Ken Gardner
Alberta Electric System Operator
1. In section 4.2.2, The AESO considers the existing applicability for model validation to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. 3. The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units. 4. Requirement R4, as written it appears owners of generating units that plan to change out the governor are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change.
Individual
Anthony Jablonski
ReliabilityFirst

ReliabilityFirst votes in the Negative for the draft MOD-027-1 standard since ReliabilityFirst believes there is a major disconnect/flaw between the Applicability Section (4.2. Facilities) and Requirement R2, part 2.1. This major flaw will create confusion on which generating units are required to be verified per the standard. ReliabilityFirst offers the following comments for consideration: 1. Requirements R2, Part 2.1 - There is a clear disconnect between the Applicability section of the standard (i.e. individual units/plants greater than 100MVA - Eastern or Quebec Interconnections) and Requirements R2, Part 2.1 which requires"… Verification of an individual unit less than 20 MVA." Based on the Applicability section, units less than 20 MVA are not applicable under this standard. Furthermore, units under 20 MVA do not fall under the NERC Statement of Compliance Registry Criteria as criteria for registration purposes for GOs and GOPs. 2.Applicability Section 4.2. Facilities – ReliabilityFirst thanks the SDT for their justification for the 100 MVA threshold, but still believes that the Applicability should be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES). Even though the 100 MVA threshold covers 80% of the connected MVA or greater for each Interconnection (in aggregate), depending on the geographic location (within the BES), that value may be much less. For example, if there is a certain load pocket in which the majority of the connected generation is lest that 100 MVA, the dynamic models would not be required to be verified per this standard. Thus not having verified accurate dynamic models for this specific location could hinder the reliability of the BES. ReliabilityFirst recommends changing the Applicability section to be consistent with the NERC Statement of Compliance Registry Criteria generator thresholds (i.e. 20 MVA or 75 MVA aggregate connected to the BES).
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
No
In Row 5, the use of 350 MVA as the cutoff for "sister unit" treatment is not reasonable. We propose the limit can be increased to 500 MVA without any adverse reliability impacts. Also, in Row 6, the allowable time for existing units to be verified following an indication of model problems should be 2 years, rather than 1 year, since existing legacy units may require additional resources to understand and resolve the issues.
1. In 4.2.1.2, the use of the term "directly connected at a common BES bus" suggests that wind farms are not applicable facilities, since wind generators are typically directly connected to a non-BES bus (e.g. 34.5 kv). We suggest that the applicability to wind farms be clarified more explicitly. 2. In R1, the present wording allows for the TP to provide only one of the three types of data, even if the GO requested all three. We suggest removing the wording, "one or more of". 3. In R1, the present requirement is for the TP to provide instructions to the GO on how to obtain the acceptable models and associated block diagrams and data. We believe that since the TP is very familiar with this data and the GO may not be, it is far simpler and efficient for the TP to provide the actual data on request, not just the instructions on how to obtain it. 4. In R2.1.1, the GO is required to have documentation comparing the "model response" to the "recorded response", in this case MW vs. frequency. First, to determine the model response requires the ability to run dynamic studies. Generally the GO does not have the simulation capability or the subject matter experts required to perform dynamic system studies. It would seem that the intent of this requirement is that the GO must expend considerable resources to gain this capability, either internally or by other means. Is this the intent of the SDT? 5. In R3, the requirements for the written response to the TP need clarification. The term "either" would suggest there are two possible responses. However, there appear to be three possible responses. We suggest there needs to be a 4th possible response option for the GO, for the GO to initiate contact with the TP to schedule a meeting to discuss the technical issues with the model. The necessary collaboration between the GO and TP to understand the model deficiencies will require time, thus may require more than the 90 days to reconcile the model issues. 120 days is suggested. 6. There is a document problem with the first sentence in R4. 7. In Section 5 Effective Dates: The considerable time and resources needed to get up to speed with model verification suggests there needs to be more time allowed in the earlier phases of the compliance timeline. We suggest using 20 percent in 4 years, 40 percent in 6 years, and 100 percent in 10 years.
Individual
Thad Ness
American Electric Power
Yes
Yes
1) In Section 4.2.3, the first line should read "Generation *in* the…". 2) In Section 5.3, the word "thirty" should be removed from the end of the fourth line. 3) In Section B, Requirement R2 contains bold faced text stating "Error! Bookmark not defined.", is this a mistake? 4) MOD-027-1 R5 ends with "...that includes the following:" yet

whatever the SDT intended to follow is missing. Please note that subparts 1 through 3 are referenced in parenthetical statements within the respective requirements and that it does not make sense that these subpart criteria are also what needs to follow "...that includes the following:"
Individual
Michael Falvo
Independent Electricity System Operator
No
Attachment 1 Row 7 leaves the impression responding to frequency excursion is merely a choice and this impression is harmful to reliability. Few “applicable units” should be unresponsive to over and under frequency excursions. If Generator Owners can choose to not help regulate frequency by simply notifying the Transmission Planner, why would any Generator Owner continue to regulate frequency? The attachment should be changed so units are unresponsive to frequency excursions only under conditions accepted by the Transmission Planner.
No
The long periods in Attachment 1 introduce too much risk to modeling assumptions used to assess transmission system reliability and to make other operating and planning decisions which do not reflect or address the actual performance of the system and equipment. This standard should not only establish the maximum period that Transmission Planners and Generator Owners to complete tasks but also to require the Transmission Planners to establish more stringent requirements when necessary to reduce the risk to reliability to an acceptable level. In some jurisdictions, e.g., Ontario, Generator Owners have 30 days to transmit the verified model, documentation and data to the Transmission Planner. Generator Owners are also required to indicate immediately following testing whether the installed equipment performed as expected. This approach has worked well. New or modified equipment must first pass through a connection assessment process to establish whether expected performance will meet connection requirements. Emerging from this process is the Generator Owner’s conditional right to connect provided he meets an obligation to demonstrate the installed equipment behaves as well as assumed during the assessment process. In this way, the risk to reliability is reduced to an acceptable level as the exposure of the decision making process to flawed modeling assumptions is minimized
a. All references to “real” power should be changed to “active” power to follow SI standard practice. b. One serious weakness is no there are explicit NERC performance requirements for frequency regulation. In some jurisdiction, e.g., Ontario, generating units are required to materially help regulate the frequency as the Transmission Planner sets performance requirements for droop, deadband and speed of response. All forms of generation are required to help regulate frequency to the extent practicable. For example, solar installations are required to reduce output during over frequency excursions. This standard in its present form allows “applicable units” to continue to not help regulate frequency could expose the BES to reliability risks. c. In Ontario, experience has been the models typically used by the Transmission Planner are not commonly employed by Generator Owners. The standard recognizes this in R1 by giving the obligation to the Transmission Planner to provide model block diagrams or data sheets to the Generator Owner. As the Transmission Planner may be unaware of practicable constraints on a unit and the Generator Owner may not be familiar with the reliability models, both parties must reach an accommodation on the details to verify the model. R2 should be changed so the Generator Owner is required to provide a model that has been verified by a method accepted by the Transmission Planner. If the Transmission Planner requires verification only with ambient measurements, then the Generator owner should be required to do verification in this way. This concept that the Transmission Planner should decide whether submissions it receives are suitable should permeate this standard. d. R2.1 should be amended (see below) to add flexibility to include other practical combinations of units to be used for verification. For example, it can be more practicable to test wind and solar installation one feeder at a time but this is not allowable with the standard in its present form. Each applicable unit’s model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification of an individual unit rated less than 20 MVA (gross nameplate rating) may be performed using either an individual unit, a combination of units, or plant aggregate model(s). e. In Ontario, we face resistance to our standards that exceed NERC requirements. It will be very helpful if the SDT in its response offers its opinion on elements of our comments that are not incorporated into the next version of this standard? For example, we would appreciate responses such as: “In the opinion of the SDT, having more applicable units on closed loop voltage control, reducing the time to transmit verified information to the Transmission Planner, having specific excitation performance requirements, expanding verified information to include limiters and other devices that affect excitation system performance, and making the requirements in this standard applicable to wider range of equipment are all practices that will tend to improve reliability.” or “In the opinion of the SDT, the requirements in this standard are not intended to preclude continuing or implementing more stringent Transmission Planner requirements.” This type of response would help us to continue to augment the continent-wide standard with additional requirements to maintain reliability in our part of the interconnection. f. We appreciate the SDT’s effort to implement our proposed language changes to remove a potential conflict with the Ontario regulatory practice respecting the effective date of implementing approved standards. The added language, unfortunately, was not added at the appropriate places. We suggest the SDT to move the wording “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities,” in Section 5.1 to right after “approved by applicable regulatory approval”, and move that same wording to right after “following applicable regulatory

approval” in Sections 5.2 to 5.4. Also, the same phrase should be appended to each of the four bullets in the Section “In those jurisdictions where regulatory approval is required:” of the Implementation Plan right after “following applicable regulatory approval.”
Group
Southern Company
Shammara Hasty
Yes
Yes
Southern Company agrees with the modifications to Attachment 1 (the Periodicity Table) as they both simplify and clarify the periodicity.
The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 8 of Attachment 1 to be deleted. Requirement R4 has a problem with the bookmark “Error! Bookmark not defined”. We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location.
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Although FirstEnergy (FE) agrees with the revision to Attachment 1, we feel that the capacity factor calculation in Row 8 should be a part of Applicability section 4.2 Facilities. The reader of the standard shouldn’t have to get to the last row of an attachment to determine as to whether a unit is exempt or not.
1.FE believes that Requirement 5 in an un-necessary requirement that the Transmission Planner must respond within 90 calendar days that the model is usable. The Transmission Planner should only respond if the information is not usable. We suggest that this requirement should be in a negative perspective and offer the following revision: R5. Each Transmission Planner shall notify the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is not usable (see Sub-requirements 5.1 through 5.5), and shall include a technical description if the model is not usable that includes (but not limited to) the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 5.1. The turbine/governor and load control or active power frequency control function model fails to to compute modeling data without error along with suggested areas for investigation, 5.2. A listing of parameters that fail the Transmission Planner's data checks, 5.3. A no-disturbance simulation fails to result in non negligible transients ("flat line"), 5.4. For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting an under-damped or critically damped response, or otherwise fails the Transmission Planner's stability criteria. 5.5. The turbine/governor and load control or active power/frequency control model submitted by the Generator Owner is either a user defined model or a model that is not acceptable for use in the Transmission Planner's Regional Reliability Organization footprint
Individual
Wryan Feil
Northeast Utilities
Yes
Yes
No Comments
Individual
Brian Evans-Mongeon

Utility Services
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Dominion
Mike Garton
Yes
Yes
There appears to be a mismatch between Requirement R2 and the Effective Date statements. Specifically, R2 is applied on an “applicable unit” bases where the Effective Date statements are applied on an “applicable unit gross MVA” basis. R4; bookmark #4 in the clean version needs to be corrected, shows ‘Error! Bookmark not defined.
Group
Seattle City Light
paul haase
Requirement 2.1.1 states three separate ways to verify MW response for a synchronous generator, but uses the term "either of" when refering to the choice of tests, which implies two tests. Please clarify with either two tests or change the reference to "any of." In addition, one of the tests of 2.1.1 includes a partial load rejection. Such a test is already part of the Kestrel test procedures currently performed by Seattle City Light. It is not clear from the requirement and footnote if our existing test would be sufficient for validation or if the other two tests would also be required. Please clarify the language of R2.1.1.
Individual
John Martinsen
Snohomish County PUD No.1
Agree
Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Individual
Mike Hirst
Cogentrix Energy
1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1. Take for example a combined cycle plant with the CTs at base load output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc. may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to “real power

response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW set point or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or Page 7 of 11 removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in comment #1 above. 3. There is presently no definition of how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. . 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid over speed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper "Testing Methods, An Overview," states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Page 8 of 11 Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in comment #1 above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, "Differences between the control mode tested and the final simulation model must be identified," and "some method of accounting for these differences must be presented," are too vague and constitute no solution at all. It would be better to just admit that trip testing can't get the job done. 6. The instruction in R4 to notify the TP, "within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control," is too vague, despite the attempted clarification in footnote #5, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. Would an output power restriction due to a broken coal feeder belt be reportable, for example? 7. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 8 of Attachment 1 to be deleted. 8. We

recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location.
Individual
Daniel Duff
Liberty Electric Power LLC
Agree
NAGF
Group
Duke Energy
Greg Rowland
Yes
Yes
We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. Equivalency of units is independent of the physical location.
Group
MEAG Power
E Scott Miller
Agree
Southern Company Services, Inc. - Gen
Individual
Eric Salsbury
Consumers Energy
No
Consumers' previous comments - The generator model with the excitation system and the load rejection testing or frequency step response testing is difficult to perform and has possibilities of damaging equipment and causing reliability issues on the system in order to perform. Previous SDT reply - The GVSDT thanks you for your comment. MOD-027 is written to allow for the use of ambient monitoring, recorded data associated with the normal operation of your equipment. A GO with your concerns can alleviate the issues you mention using ambient monitoring. While we agree with the reply by the SDT when ambient monitoring is available, it is not available on all of our equipment. Therefore, we stand by our previous comments.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power System Planning agrees with the revisions made to Attachment 1.
Yes

Idaho Power System Planning agrees with the revisions made to Attachment 1.
Attachment 1 – Note 1 Idaho Power System Planning comments Attachment 1 discusses unit model verification to a frequency excursion using a recorded response from the generating unit. Attachment 1, Note 1 defines the frequency deviation criteria. Idaho Power System Planning asks the GVSDT to include the minimum acceptable data sampling criteria of the recording equipment as part of the Note 1 criteria. Requiring each Transmission Planner to maintain a list of acceptable models, and then requiring Generator Owners to submit data according to those models is unreasonable. The list of acceptable models needs to be at least regional, if not continent-wide. In addition, some required longevity needs to be specified to allow Generator Owners to appropriately plan and perform the verification work.
Group
JEA
Thomas McElhinney
JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Individual
Kirit Shah
Ameren
No
We believe that there is a discrepancy between the language in the requirement and VSL for R4 and Row 4 of the Attachment 1. In the requirement, a 180 day period is stated, while in Row 4 of Attachment 1, a 365 day period is stated.
Yes
(1)As a general comment, NERC should make all the papers listed in the references section of the standard readily available on their website. (2)There appears to be an extra word "thirty" in both redline and clean versions of the standard under section 5.3 of the Effective Date section of the draft standard. (3)As we understand, part of R1 is for the Transmission Planner to provide instructions on how to obtain the list of acceptable model types for use in dynamic simulations. In this regard, we ask the SDT if this would preclude the use of user-written models? (4)We still have serious concerns about compliance with new MOD-027-1 while compliance with MOD-012-0 and MOD-013-1 is still in effect as explained in our response to draft MOD-026-1. We strongly request the SDT seriously consider incorporating the current MOD-012/MOD-013 submittal requirements within MOD-026 and MOD-027. This will synchronize the reporting and verification requirements and help minimize the resource burden of compliance with both efforts. At the same time it will create consistency across the country.
Individual
John Yale
Chelan PUD
Yes
Yes
Note 2, Page 4: It is unclear what would constitute and acceptable accounting - "Some method of accounting for these differences must be presented..." Unless any accounting would be acceptable, suggest some guidance.
Individual
Maggy Powell
Exelon Corporation and its affiliates
Yes
Yes

1. Exelon previously commented that MOD-027-1 R5 implies that it is the Generator Owner's responsibility to ensure that the model is "useable" based on the criteria specified in Parts 5.1 through 5.3; however, it is at the discretion of the Transmission Planner. As written, the requirement gives the Transmission Planner the discretion to reject the model based on governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09. Exelon again reiterates that the usability of the model should not be confused with a model that accurately represents the generating unit governor and provides projected results. 2. Please confirm that the number of generating units combined into the percentage for implementation of unit verification includes those generating units that may have a documented exclusion such as an existing unit that does not have an installed control system. 3. MOD-027-1 R4 appears to have a formatting issue – the statement "Error! Bookmark not defined" is in bold letters within the requirement.
Individual
Teresa Czyz
Georgia Transmission Corp.
Yes
Yes
Group
Luminant
Brenda Hampton
Yes
No
While Luminant agrees with the concepts in the periodicity requirements in Attachment 1, it would be beneficial for the drafting team to clearly identify that units that are base load (row 7) are excluded from model verification.
Individual
Don Jones
Texas Reliability Entity
1) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is “directly connected” to the BES. Please consider reviewing the language to see if it should instead say “included in” the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not “directly connected” to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. 2) Requirement R4: Suggest removing the phrase “or plans . . .” and rewording as “Each Generator Owner shall provide revised model data for each applicable unit . . ..” There appears to be a footnote error here – delete “6”? 3) TRE recommends changing to “Planning Authority or Transmission Planner” in the Functional Entities in Section 4.1.2 instead of “Transmission Planner”. This change should be duplicated in the requirements. The change may be needed since the Planning Authority or the Transmission Planner may have the responsibility for modeling the generation data provided by the Generator Owners.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
No
(1) While the clarity of Attachment 1 has been improved, we noticed a couple of issues. Note 3 provides guidance for early compliance and we agree that early compliance should be allowable. It establishes that 10 year period begins from the transmittal date. If a GO has data that satisfies the early compliance condition for a verified model and that data is a five years old, the Note would appear to allow the GO to transmit the data to the TP and receive credit for next 10 years effectively creating an initial 15-year re-verification cycle. Is this intended? If not, please provide more guidance for how soon the GO would have to re-verify its model. (2) Row 4 in Attachment 1 states

that it applies to initial verification for a newly applicable unit or for an existing applicable unit with a new turbine/governor and load control or active power/frequency control equipment control system. However, Requirement R4 also applies to changes to the same control system. Wouldn't complete replacement be a change? We recommend modifying Attachment 1 to avoid this overlap. (3) Per Requirement R4 and Row 6 in attachment 1, the GO has 180 days to submit a plan to Transmission Planner to verify the model and then another 365 days to perform the model verification date. That would appear to give the GO approximately a year and half to complete the verification for changes (including replacement) to the control system. Requirement R2 and Row 4 appear to require completion of the verification in 365 days or a year. Please modify the table or requirement to clarify appropriate application.
(1) Thank you for modifying the applicability section. It is greatly improved and is much clearer than the previous version. However, we believe there are a few additional minor refinements necessary. First, generators can be and are part of the Bulk Electric System. Thus, we suggest changing "Facilities that are directly connected to the Bulk Electric System (BES)" to "generation Facilities that are part of the Bulk Electric System." Otherwise, there might be some confusion if the drafting team intends to draw in generators that are not part of the BES. Second, we find the wording "will be collectively referred as an 'applicable unit' that meet the following" confusing. We think the intent was to clarify that an applicable unit is one that is part of the BES and meets criteria established in section 4.2.1, 4.2.2, and 4.2.3. However, we think the inclusion of the "will be collectively referred as an 'applicable unit'" is superfluous. Because the section is the applicability section, we think this language could be struck for clarity and the applicable units will be understood to mean those that meet the criteria in section 4.2. As an alternative, the drafting team could explain in a footnote what they mean by the term applicable unit. Third, with the two proposed changes, we think the final wording of section 4.2 after the opening clause should be "generation Facilities that are part of the Bulk Electric System (BES) that meet the following criteria:". (2) In requirement R2, please change "for each applicable unit" to "for each of its applicable units." This is the previous wording and is more correct. The current wording literally says that the GO must provide a verified model for each applicable unit including those it does not own. After all any unit that meets applicability criteria including those owned by other GOs would be an applicable unit. (3) Please specify in M1 that a Transmission Planner may also provide an attestation that no such request was received if this is the case. Use of an attestation that an event did not occur is established as an acceptable form of evidence in CAN-0030. Furthermore, precedent has been set in the use of attestations in measures in FAC-003-2 M1 and M2. (4) We continue to believe that the examples provided in the comment form should be included in the standard. Please create an Application Guidelines or Guidelines and Technical Basis section in the standard and add them. This has become common practice with developing standards. We do not understand why the drafting team would not want to retain such information that helps readers understand the standard and that has already been developed. Furthermore, it would make it easier for commenters to see what has changed in the examples because a red-line of the standard is required. Because the examples were contained in the comment form this time and during the previous posting, it is not easy to deduce the changes because there is no red-line. If the examples are not included in the standard, please provide more explanation than was provided during the last response to comments which was that it is not appropriate to include the examples. We do not understand why it is not appropriate. (5) We disagree with the need to retain the latest model verification evidence under Requirement R2 and M2. First, this is not consistent with the Section 3.1.4.2 of Appendix 3c to the NERC Rules of Procedure section which states that the audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Since the audit cycle for a GO is six years and the model verification period is 10 years, the GO will have to retain data past its prior audit period. Furthermore, the auditor will have already had an opportunity to review the model verification data during the last audit. Presumably, if they did not find any compliance violations, there should not be a need to review this data again. Thus, the data retention should not exceed the six year audit cycle. (6) How will mothballed units be handled in Attachment 1? If a mothballed unit is returned to service which row in Attachment 1 applies? What if the unit was mothballed before the effective date and returned to service after all stages of the effective dates? What if it was mothballed after an initial verification? How does this affect the next verification date?
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
Why wouldn't the GVSDT just identify (i.e. show reference note on Attachment 1 table) that "Applicable units does not include units that don't respond to frequency excursions (e.g. base-loaded units)"?
In trying to follow the flow of this standard, it is obvious that R1 precedes R2 logically. But then it also appears that possibly R5 actually takes place before R3. There does not seem to be any requirement for the Transmission Planner to provide Written Comments to the GO that address the second and third bullet points of R3. It seems that a requirement should be added for the TP to provide written comments for any of the 3 bullets shown in R3; however, only the first bullet of R3 has been required of the TP (in R5) as the standard is currently written in Draft 3. The first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a

GO has identical equipment at different physical locations, they are equivalent. Equivalency of units should be independent of the physical location. Other minor edits: • In A.5.1 for the Effective Date, it should say R3 through R5 (not R6, as there is no R6). • Also, by footnote 4 on R4, there appears to be some sort of "Error! Bookmark" from when the footnotes were changed. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1. Take for example a combined cycle plant with the CTs at baseload output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to "real power response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW setpoint or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the generator modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in our comments above. There is presently no definition of how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid overspeed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper "Testing Methods, An

Overview,” states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in our comments above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, “Differences between the control mode tested and the final simulation model must be identified,” and “some method of accounting for these differences must be presented,” are too vague and constitute no solution at all. It would be better to just admit that trip testing can’t get the job done. The instruction in R4 to notify the TP, “within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control,” is too vague, despite the attempted clarification in footnote #5, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. Would an output power restriction due to a broken coal feeder belt be reportable, for example?
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No comments on the question.
No
No comments on this question.
A stated purpose of Generator Verification is “to ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.” Modeling behind-the-meter generation based on gross name-plate ratings will not accurately reflect those assets’ capabilities or operating characteristics, and, in fact, may seriously distort BES expansion plans or other modeling scenarios if name-plate ratings are used. Behind-the-meter generation is a misnomer. It is not comparable to utility or merchant generation in which the primary function is to deliver electric energy to the bulk electric system. The primary function of behind-the-meter generation that employs cogeneration or combined heat and power (CHP) systems is to deliver thermal energy (usually in the form of steam) in support of the load’s process technology. In the case of industrial loads, the capabilities or operating characteristics of that process are a function of the load’s production schedule associated with its products (e.g., chemicals, petroleum, paper, etc.) and independent of conditions on the BES. Any electric power delivered to the BES is a residual by-product of the industrial process and generally a small fraction of the name-plate rating of the generator. Section III.c.4 of the Statement of Compliance Registry Criteria (v.5) and Exclusion E2 of the revised BES definition both recognize this fundamental characteristic of behind-the-meter generation and that is why neither document uses name-plate rating as a useful metric for behind-the-meter generation. The GVSDT is urged to do the same.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Darryl Curtis
Oncor Electric Delivery Company
No
Oncor does not support the position that the Transmission Planner (TP) is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the Planning Authority (PA) only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
No
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Oncor does not support the position that the TP is applicable for this standard. In the ERCOT Interconnection, Section 3 and Section 5 of the ERCOT Nodal Operating Guides prescribes the ERCOT ISO to request and receive

generation unit performance data, not the TP. Oncor takes the position that a regional variance be granted for the ERCOT Interconnection such that the standard would prescribe that the PA only be the only requestor and receiver of unit performance data to support Section 3 and Section 5 of the ERCOT Nodal Operating Guides.
Individual
Russell Noble
Cowlitz PUD
No
Cowlitz supports the comments of the NAGF SRT: 1. The SDT should consider moving the capacity factor exemption information found in Attachment 1, row 8 into the applicability section. The applicability section should allow an entity to be able to determine if the standard applies to them and be able to determine the scope of the facilities affected. It is best for those impacted to immediately know which units are in the scope and not have to realize the scope from a detailed study of the table of Attachment 1. This would allow row 8 of Attachment 1 to be deleted.
Yes
Cowlitz supports the comments from the NAGF SRT: 1. The standard is based on the assumption that it is possible to tune the acceptable models cited in R1 such that their predictions will match actual power output responses to system Disturbances. The yet-to-be-defined acceptable models may not be capable of achieving this goal, however, because standard governor component models are inadequate to predict with high fidelity the generation system response that is the subject of MOD-027-1. Take for example a combined cycle plant with the CTs at base load output and the steam turbine in the sliding pressure mode (HPT control valves wide-open). Governor-only models will show a demand for increased output if a system frequency dip is postulated; yet absolutely nothing will happen in real life, because the fuel input to the CTs is already maxed-out and the STG has no throttle reserve. The situation for a fossil unit is analogous, with non-governor-model factors such as throttle reserve, boiler thermal inertia, mill ramp rates, control valve slew rate and hysteresis, the output cap associated with going VWO, furnace and duct pressure limits, fan stall run-back routines and the like all having an impact on the outcome, depending on the time-scale involved. Sustained Disturbances with fluctuations of system frequency above and below 60 Hz pose even greater challenges, as the response characteristics of controls systems for fuel, air, drum level etc. may become temporarily destabilized. A key clarification is needed in this respect. The references in R2.1.5 to "real power response" and in R3 (3rd bull-dot) to "the recorded response" indicate that models complying with MOD-027-1 must cover the factors cited above, but R2.1.5 also speaks of elements that "override the governor response." Including in models only load control function blocks that impose a max-MW set point or otherwise modify the governor output signal may not pose a problem; but the effects of all factors that cause the actual MW response to lag or otherwise vary from the governor output demand signal can be captured only by dynamic simulators, not governor models. Simulators involve enormous cost and demand on engineering resources, and can be justified for only a handful of the largest generation plants. The SDT is therefore asking for a considerable advancement in the excitation modeling state of the art, to be undertaken in parallel by the owners of every generation unit in North America. This is a doubly daunting task in that GOs often do not have any dynamic modeling software or expertise, much less the ability to invent something new, because the present approach to the subject is that GOs just provide the values of input parameters to the TP, which owns and runs models. Independent GOs (i.e. deregulated entities that are not part of a vertically-integrated utility) moreover do not have and cannot obtain information on the system outside the plant battery limits. This circumstance renders them unable to model the plant-T&D interactions associated with Disturbances, and independent GOs may therefore forever remain unable to develop model results that closely match actual Disturbance responses. The approach being taken in MOD-027-1 is consequently viewed as being technically infeasible for the present state of the art as well as unjustified in light of FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised orremoved [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. The SDT should instead collaborate with industry associations (EPRI, IEEE, NAGF), equipment OEMs, and modeling services vendors to develop the right tools for the job, and put the new models through trial runs at several plants. These trials should be limited to data-collection means that can be non-invasively employed (e.g. short-term on-line monitoring, and controlled perturbations during normal-stop events), and should lead to definition of specific testing means for definition of specific model parameters. The SDT should then put out for voting a standard requiring TOPs to own and run these models and requiring GOs to provide them the appropriate input data, developed via the non-invasive means stated above. 2. The complexity of the task at hand is compounded by the circumstance that generation unit response may vary widely depending on the output level at the time a BES upset occurs (as in the combined cycle example above). There are no specifics in MOD-27-1 regarding this aspect of reliability standard scope, however, just a requirement that the model shall match the actual response. The implication appears to be that a close correlation is needed for all upset magnitudes and all possible initial conditions, which brings us back to the dynamic simulator objections in comment #1 above. 3. There is presently no definition of how closely the model must match the recorded response or for what period of time, just a requirement that it be deemed "usable" by the TP. The SDT is asking for a blank check, and we cannot agree to regulations for which it is impossible to say at the time of balloting

whether or not compliance can be achieved, let alone in a fashion that is justified per the FERC order cited above. Perceived shortcomings in these respects would presumably trigger the TransmissionPlanner expression of concern described in R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026 and been found lacking. . 4. R2.1.1 and the verification table in the standard allow the alternative of an on-line speed governor reference change test, but such testing is not always possible. Where it can be attempted there is risk of creating a larger-than-desired Disturbance, possibly threatening grid stability or tripping the generation unit. Making GOs create Disturbances if they do not naturally occur is not a good idea. NERC should consider directing TOPs to construct load banks, which they can tie-in and cut-out to jar the system for response test purposes. 5. R2.1.1 and the verification table also allow partial load-rejection tests. The SDT may have envisioned rejection to house load, followed by rapid re-synchronization, but such an outcome cannot be expected. House load is often below the minimum stable output (always below for coal-fired and nuclear plants), and it is always far below the minimum environmentally-acceptable load for fuel-burning units. The need to avoid over speed following load rejections meanwhile generally requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. Trip testing may additionally be extremely disruptive and costly. Power Technologies, in their paper "Testing Methods, An Overview," states that five episodes may be required, which would be enormously expensive for combined cycle plants with a fixed dollars per trip figure written into the long-term service agreement. Such expenditures might nonetheless be justified, if the information obtained is of sufficient value; but, as explained in comment #1 above, trip tests will yield data only for standard governor models and not for the on-line extra functions for which information is evidently being sought. Footnote 2 of MOD-027-1 indicates recognition of this shortcoming. The solutions offered however, "Differences between the control mode tested and the final simulation model must be identified," and "some method of accounting for these differences must be presented," are too vague and constitute no solution at all. It would be better to just admit that trip testing can't get the job done. 6. The instruction in R4 to notify the TP, "within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control," is too vague, despite the attempted clarification in footnote #5, since many activities can have some degree of impact as noted above. Reportable thresholds regarding degree of impact on system response and the expected duration are needed. Would an output power restriction due to a broken coal feeder belt be reportable, for example? 7. We recommend removing the first element of the logical AND statement of Attachment 1 Row 5 (the same physical location element). If a GO has identical equipment at different physical locations, they are equivalent. A sister is a sister independent of the physical location. As long as the equipment is identical, the concept should be allowed to apply regardless of location.
Individual
Don Schmit
Nebraska Public Power District
Agree
MRO NSRF

Kathleen Goodman
ISO-New England
Yes
Kathleen Goodman
ISO-New England
No
Attachment 1, Row 4 allows for transmission of a verified model 365 days after commissioning of a new generator. This is an unacceptable length of time for a generator to be on-line from both a reliability standpoint and this length of time is in conflict with ISO/RTO Standard Generator Interconnection Agreement language. The ISO/RTO Standard Generator Interconnection language requires Generator Owners to provide verified models ***prior to*** Commercial Operation.
Kathleen Goodman
ISO-New England
Attachment 1, Row 8 has a reference to capacity factor. The capacity factor section has been removed from the body of the standard. If the capacity factor is still part of the standard by it's existence in the Attachment then this is unacceptable. Older large units with low capacity factors will be called upon to operate during extreme weather events when the system is most stressed. System reliability will be compromised if the modeled characteristics of the units differ from what is actually installed in the field.

Requirement R1 may bring out some concern over the copyrighted models supplied by the simulation software vendors. Hopefully this can be worked out with the vendors.

Requirement R3 might only require a “written response” from a Generator Owner to the Transmission Planners notification that a model is not useable with some technical basis for keeping the current model that is not usable. Wording must be included so that ultimately the Generator Owner shall provide a “usable model” to the Transmission Planner.

Requirement R5 sub-requirement wording should be changed to indicate the Transmission Planner shall notify the Generator Owner if the excitation model does not initialize, a no-disturbance simulation results in transients or a disturbance simulation results in a model exhibiting negative damping.