Name (34 Responses)
Organization (34 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
Question 1 (39 Responses)
Question 1 Comments (53 Responses)
Question 2 (38 Responses)
Question 2 Comments (53 Responses)
Question 3 (40 Responses)
Question 3 Comments (53 Responses)
Question 4 (38 Responses)
Question 4 Comments (53 Responses)
Question 5 (0 Responses)
Question 5 Comments (53 Responses)
Question 6 (41 Responses)
Question 6 Comments (53 Responses)
Question 7 (35 Responses)
Question 7 Comments (53 Responses)
Question 8 (0 Responses)
Question 8 Comments (53 Responses)

Individual
Frederick R Plett
Massachusetts Attorney General
No
a particular unit may not pose much problem to a system but an aggregation may. One would think that over a threshold # of MW that active close loop regulation functions should be present.
Yes
No
I am concerned about units that may be individually less than 20 MVA but collectively could eb much larger - wind farms.
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
No
While some plants may not have excitation systems, they can have complex reactive coordination controllers whose settings and functions should be tested and verified.
Yes
No
Footnote 4 in the Applicability Section implies comparing simulated unit or plant responses to dynamic system events. Verifying the model only after an event as is called for in footnote 4 is completely counter to increasing system reliability. Analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. The Applicability Section needs

further revision because by requiring only generators above 100 MVA with unit capacity factors above 5 % to test excludes an unacceptably large amount of installed generation. For example, about 30% of the installed generation in New England would not therefore, require model validation. This is an excessively large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being most stressed and reliable operation is being most challenged. If the objective of the Standard is to develop the right models for dynamic suimualtions, models must include high and low capacity factor units, transient and long term models, etc. for all network conditions. A model for the generators and associated equipment is supplied in accordance with MOD-012. The accuracy of such models may be limited and a higher percentage of generator validation is required. Footnote 4 should be changed to allow verification of generator models not required under the Applicability Section to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical. Requirement R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate. What is meant by a “technically justified request” from the PC? R5 refers to the Planning coordinator, yet the Planning Coordinator is not listed in the Applicability Section of MOD-026. MOD-026 deviates from the NERC Functional Model Version 5 in that MOD-026 R5 has the Generator Owner communicating with the Planning Coordinator. The NERC Functional Model stipulates that the Transmission Planner communicates with the GO/GOP. The PC then collects the data from the TPs in its area, and from adjacent PCs. The Standard should be consistent with the NERC Functional Model.
Yes
While supporting the clarification of capacity factor concerns, there is concern with the exclusion for units with less than a five percent capacity factor. See comments provided to Question 3. Average Capacity Factor should be defined.
Use of the terms Bulk Electric System (BES) in the Purpose and bulk power system in the Facilities Section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). In the Applicability Section under the Introduction, the bullets under 4.2.1.2 are unnecessary. The wording of 4.2.1.2 already covers what the bullets detail. Regarding Requirement 2: • R2.1.1: requires that model results must “match” results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be a stipulated allowable tolerance band. Suggest that a tolerance be a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the bus voltage being controlled. • R2.1.1: A unit’s “point of interconnection” is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term “point of interconnection” may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the bus controlled by the generator excitation system. Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. Why are the References listed in Section G included? They are described as being “beyond the scope of this Standard”. The language for R4 should be reworded as follows: “R4. Each Generator Owner shall provide revised model data or plans to perform model verification7 (in accordance with Requirement R2) to its Transmission Planner within 180 calendar days of prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response8 characteristic.” The way the language is currently written, the generator has to provide its revised model data or plans to perform model verification within 180 days of making the change. For up to 180 days after a change has been made the correct data still may not have been made available to the Transmission Planner. This could have a significant impact on reliability. The suggested rewording addresses this possibility. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs. What is the definition of Gross Nameplate Rating as used in the Standard?
Yes
No
The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard allows loopholes which undermine reliability.

Suggest revising Requirement 5.6 from “may retroactively grant a temporary exemption” to “may grant a retroactive temporary exemption”. The magnitude of voltage excursions at the point of interconnection may be different from the generator terminals where generator relays receive their voltage inputs.
The definitions of the terms Frequency Excursion and Voltage Excursion were deleted. All references to these terms should be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use the lower case terms. Regarding requirement R2, the time duration is acceptable. However, the band is shown as 0.95 per unit to 1.05 per unit at the point of interconnection, and there are areas of the power system that have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 per unit to 1.05 per unit. Failure to make this change means that it would be acceptable for generators to trip during steady state operation of the system on “low” voltage. Unanticipated and unncecessary tripping of generators under steady state conditions could lead to significant reliability concerns on the system. The PTs connected to the high voltage terminals of the GSU may not be used as a source for generator protective relaying. Generator protective relays may be connected to the generator output terminals for their source of potential. The wording of R2 should incorporate generator terminals in addition to point of interconnection. Regarding R3, in the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the “No Trip Zone”, there is no requirement to correct the issue. The generator must only document the limitation. This completely undermines the intent of this standard. It is counterproductive to set undervoltage relays to meet the curve if other equipment is still going to trip the plant for those same conditions. This standard appears to simply document system concerns rather than identify and correct them. Under Requirement R5, 5.5 (exception) is unnecessary. It does not have to be stated that a generating unit or generating plant may trip if clearing a system fault necessitates disconnecting the generating unit or generating plant.
Group
Luminant Power
David Youngblood
Yes
Yes
Yes
No
Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross and Net). The standard should specify Net Capacity Factor.
No
An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
No
Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The “maintain” requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.

1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the “no trip zone” of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become “Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds.” For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; “ … unless the generator owner has identified an equipment limitation …” 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. 4. Overall, this standard should address voltage and frequency relay settings only.
Group
Progress Energy
Jim Eckelkamp
Our AFFIRMATIVE vote is conditional upon the "Clean" version being voted on. There are major differences between the Red-line and clean version in Section 5 "Effective Date". The Clean version 5.1.3 requires 50 % where as Red-line version has 100 %
No
Progress Energy has a concern associated with the voltage ride through curve referenced in R5 (Attachment 2). The concern is not about setting the relay protection to ride through this transient or the generators capability of riding through such a transient but of the physical capability associated with the large pumps and motors in the auxiliary equipment that would be subjected to this transient. A lot has to do with the size of the motors at the 4160 or 6900 volt level and the control relays at the 480 volt level. After 9 cycles at zero voltage the phase of the motor decay voltage and the incoming line voltage of the large motors may have shifted significantly causing large currents to be drawn when the voltage is restored to the motor. This could cause significant cyclical torques on motor shafts that can damage the shaft over time. Also the control contactors for most 480 volt control circuits do not hold in for less than 60 -70 % voltage. The capability of UPS systems are not sufficient to power the large motors being discussed and it may not be feasible to UPS all the plant 480 volt control circuitry. (We wouldn’t be concerned with 480 if we thought we would lose higher voltage equip…) To implement this requirement as presently worded appears to be impractical and could prevent building of any new generating facilities at reasonable cost. There needs to be some ability to deviate for the specific requirements of the voltage curve in Attachment 2 if it can be show that the fault clearing time for the bulk electric system that the unit is connected to is different than the specific voltage requirements of Attachment 2 or there needs to be some more specific wording excluding the auxiliary equipment from the requirements of this voltage curve.
Individual
Dan Roethemeyer
Dynegy
Yes
Yes

Yes
Yes
The division of responsibility (between GO and TP) in the task of ‘verifying’ the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and ‘verify’ the models. This would also eliminate the question of what constitutes a ‘verified’ model, i.e., how good is good enough.
Yes
Yes
No
Group
Texas Reliability Entity
Don Jones
Yes
Yes
Yes
(a) R5 should be limited to generating units and plants that meet the Registry Criteria. For clarity, we suggest rewording R5 with “…perform a model review of any generation unit or plant meeting the Registry Criteria, but not included as an applicable unit in Section 4.2, that includes one of the following…”. (b) Does similar language (i.e. section 4.2.4) need to be added to MOD-027-1?
No
We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units meeting the MVA thresholds, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an “applicable unit”.
1) Applicability: The applicable Facility requirements should be the same for every Standard in this Project! 2) Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection. 3) Effective Dates: Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correcting model errors that may lead to (or have led to) improper planning of the system based on the current model results. 4) The SDT should consider moving the “Consideration for Early Compliance” criteria from Attachment 1 into the Effective Dates section. 5) Regarding Requirements R3 and R4: The inclusion of “or a plan” extends the timeframe associated with getting good modeling data to the TP. What does the Transmission Planner do in the interim? Who is responsible for the use of the unusable or invalid data? Does the unusable or invalid data get used at all (do the plants need to disconnect until “usable” data is provided)? 6) Regarding VSLs for R1, R3, R4, R5 and R6: The numbers of days stated in the Severe VSLs need to be reconsidered. For example, in the Severe VSL for R1, no VSL applies if the performance occurs on day 181. 7) Regarding VSL R5: There is reference to Subpart(s) 5.2 and 5.3 in the High and Severe VSL text, but there are no corresponding subparts in the Standard. 8) Regarding Attachment 1: The allowed time to provide usable verified models is far too long. For example, as written there could be a gap of almost two years between the time a TP learns that a model is “unusable” and the time the GO has to provide a verified model. 9) In

Attachment 1, change “356 days” to “365 calendar days” in the third line of the table for consistency.
No
Most existing facilities are likely not designed to a frequency or voltage ride-through standard, and a useful estimate may be very difficult for owners to provide. Generator Operators may be able to document “known” equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation.
No
While it is technically feasible to set generator protective relays to meet the intent of this Standard, there are technical limitations that may prevent manufacturers from achieving it, especially if the term “generating plant” includes auxiliary equipment within the plant that is required for the generator to continue to operate. The standard needs to clarify if and how the limitations of auxiliary equipment are to be addressed in connection with applicable generating facilities.
1) Purpose Statement: If we correctly understand the intent, the second comma should be removed. 2) Does the SDT want to consider any specific requirements regarding generators that are connected as synchronous condensers, and is it the intent of the standard to cover this operating mode? 3) All requirements: Need to clarify the phrase “generating unit or generating plant”. Does the “generating plant” phrase imply that the frequency and voltage setting criteria also applies to plant auxiliary equipment (referenced in R4)? In ERCOT, we have seen multiple instances where close-in faults have created low voltage conditions which caused auxiliary equipment to trip (boiler feed pumps, baghouse fans, etc.) which in turn caused a unit runback and trip. If the intent of this standard is to also cover plant auxiliary equipment, then this needs to be very clearly stated in the Applicability section and/or in the Requirements. 4) R1 and R2: The SDT may want to consider adding Volts per Hertz criteria. For example: ERCOT region criteria currently states a generator must remain connected if Volts/Hertz is less than 105% of generator design voltage and frequency, and also if Volts/Hertz is less than 116% of generator design voltage and frequency for less than 1.5 seconds. 5) R1: Need to add “or generating plant” to end of R1. 6) R2: Need to specify that the undervoltage “no trip zone” applies to both single-phase and three-phase voltage excursions. 7) R2.1.2 and 2.1.3 need to include the phrase “generating unit or generating plant” versus “generator” to be inclusive of a plant site and provide consistency throughout Standard. 8) R1 and R2 Exclusions: The SDT may want to consider these additional exclusions: a. A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system. b. A generation unit may trip by frequency or voltage protection if the unit is being operated below its Low Sustained Limit (LSL), where LSL is defined as the limit established by the Generator Operator that describes the minimum sustained energy production capability of the generator. c. A generator unit may trip by frequency or voltage protection if the unit is being operated in a “Test” status and is not under AGC control. 9) R3: Generator Operators should be required to document “known” equipment limitations. There are probably many examples of unknown equipment limitations, simply because a plant may not have experienced a fault condition that could expose the limitation. Also need to clearly state if this requirement (i.e. due to the phrase “generating plant”) also applies to plant auxiliary equipment, which would require the GO to provide extensive review and documentation on all of their plant auxiliary systems as well. 10) R5: Need to clearly state if this requirement applies to plant auxiliary equipment. 11) In 5.2, insert “nameplate” after “aggregate” to be consistent with R5.1.1. 12) R5 Exceptions: The SDT may want to consider these additional exceptions: (a) A generating unit may trip by frequency or voltage protection while a unit is being brought on or off-line, if the trip does not result in the loss of generation to the system. (b) A generator unit may trip by frequency or voltage protection if the unit is being operated in a “Test” status and is not under AGC control. 13) In Measures M1 and M2: See comment 3 above regarding the use of the phrase “generating plant”. Is it the intent of these measures to also cover frequency and voltage setting sheets for plant auxiliary equipment protection systems? 14) In Requirement R4, Measures M4 and M5, and some VSLs: Remove capitalization of “Frequency/Voltage Excursions” and similar terms (e.g. Frequency Excursion), which are not formally defined in this standard nor in the NERC glossary. 15) VSLs for R1, R2, and R3: What is the SDT’s intent regarding a GO that has set its relays per R1 and R2, and has no documented equipment limitations per R3, but still experiences a unit trip within the one of the “no trip” zones in Attachment 1? Is that intended to be a violation of this standard? There is not a VSL for this situation. The VSL for R5 contemplates a violation for tripping in the no-trip zone, but it only covers “new” generation units, and there is not a similar VSL

for existing units. 16) VSL for R1 and R2: The term “technical” should be replaced with “equipment” to be consistent with the Requirements. Need to replace “generator” with “generating unit or generating plant” to be consistent with the Requirements. 17) VSL for R2: Language should be similar to VSL for R1 with respect to “activated to trip” phrase and to be consistent with the Requirement itself. Suggest replacing “conditions” with “criteria” to be consistent with VSL for R1. 18) VSL for R3 and R4: What VSL applies if the communication occurs on day 61? It looks like the answer is “none.” 19) VSL for R3: See comment 9 regarding requirement R3 above. The requirement and VSL should only apply to “known” equipment limitations. 20) VSL for R4: Consider changing “unit’s performance” to “unit’s or plant’s performance.” 21) VSL for R6: Remove the phrase “or limitations,” because R3 discusses limitations and the reporting thereof and it is out of place here. 22) Attachment 1- Change “Texas Interconnection” to “ERCOT Interconnection”. 23) Regarding the Voltage Ride-Through Curve Clarifications: The reference to a generation facility’s “point of interconnection to the Bulk Electric System” is incorrect, because the generation facility is itself part of the BES. We assume this is intended to refer to the point of interconnection between the generation facility and the transmission facility, and the text should be modified accordingly.
Individual
Matthew Pacobit
AECI
Yes
Yes
No
I believe that the threshold of 20 MVA is too low. I would recommend a threshold of a (> 75 MVA)
Yes
No
My concern with this requirement is that if a GO provides an estimate of how long they believe that the unit can ride out the event, then what will happen if they do not make this target? Will the GO be held responsible for not making this time? Due to this concern how accurate are these times that are provided by the GO going to be and how much will be a built in cushion?
No
In my opinion, there needs to a definition of what is considered to be a new plant. Many plants are being built that were actually plants and projects that started 10 years ago. I do not believe that those plants should be included.
Individual
John Seelke
PSEG
Yes
Yes
The examples in the unofficial comment form should be incorporated into an attachment to the standard for ease of reference.
Yes
Yes
We have these additional comments: a. 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. b. The entire section 4.2 has language that includes “directly connected to the bulk power system.” The BES is a subset of the BPS (per Order 743), and the GVSDT should consult with the SDT for Project 2010-17 – Definition of BES – to develop alternate language that instead refers to the BES.
Yes
We do not know whether new units installed 6+ years out can meet the requirements. We suggest that the team should reach out to OEMs for their input.
We have these additional comments: a. In Part 4.1 of R4, the first sentence has this proposed change, indicated by capilatization: “An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection [deleted “described by”] THAT WAS DEVELOPED FROM A dynamic simulation provided by the Transmission Planner. b. M5 is confusing. M5 states “Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a Frequency Excursion or Voltage Excursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip.” i. Frequency Excursion and Voltage Excursion are capitalized terms – the previous version’s defined terms were supposed to be removed. ii. While is appears that an “attestation that the generating unit or generating plant did not trip” is only required for a unit or plant that remained on line during a frequency or voltage excursion, the language should be made clearer. iii. We suggest that the GVSDT consider rewording M5 to clearly state what trips should be reported, whether non-trips that occur during frequency and voltage excursions are to be reported, and what supporting evidence (or attestations) is required for each reported item. A table may be the best way to display this. Finally, M5 should be developed to produce the VSL metric for R5. c. The previously defined terms “Frequency Excursion” and “Voltage Excursion” were to be removed from this draft; however they are used in R4 and in the VSL table. The GVSDT should search the standard for all such usage and correct it.
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
Yes
Yes
Yes
Yes
Yes
Yes
We would suggest revision of M5 to read. Also since the two terms Frequency Excursion and Voltage Excursion are no longer to be defined by this project we would ask that you use the lower case for these terms in the standard. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a frequency excursion or voltage excursion as specified in Requirement R5, or evidence that a listed exception applied.
Individual
Chris de Graffenried

Consolidated Edison Co. of NY, Inc.
No
Requirement 5: • R5 authorizes the PC to apply MOD-026 to any generator not included in the Applicability section of MOD-026. This would authorize the PC to apply the standard to non-BES generation, which is not appropriate. • It is not clear what constitutes a “technically justified request” from the PC. • Refers to Planning Coordinator, but PC is not listed in Applicability section of MOD-026. • Further, under NERC Functional Model Version 5 the Transmission Planner communicates with the GO/GOP. The PC collects data from the TP’s in its area and from adjacent PC’s. See NERC Functional Model Version 5. The standards should conform to the NERC Functional Model.
Use of terms Bulk Electric System (BES) in the purpose and bulk power system in the Applicability section should be reconciled. NERC is standardizing on the term Bulk Electric System (BES). Requirement 2: • R2.1.1: requires that model results must “match” results from field testing. This language implies that there is zero tolerance which is unreasonable. There should be some stipulated allowed tolerance band. We suggest that a tolerance is a specific value based on per unit. For example, the model and actual response shall match within a tolerance of .02 per unit of the buss voltage being controlled. • The units “point of interconnection” is open to interpretation and could create compliance uncertainty. Almost all generator excitation systems control the generator terminal voltage (low side of the GSU) while the term “point of interconnection” may be interpreted as on the substation bus (high side of the GSU). A suggestion is use the following: at the buss controlled by the generator excitation system. The Applicability Section of the Standard, Section 4.2 permits exclusion of generators with a low capacity factor (< 5%). Why should the Standard allow an exemption for low capacity factor units? The objective of the Standard is to develop good excitation models for dynamics simulations, which are often conducted under high load conditions. At higher loads, these lower capacity factor units are frequently needed and operating. Therefore the Standard should apply to even lower capacity factor units. Tables following Attachment 1: the purpose of these tables is not clear, they are not referenced in the Requirements. Note, there is an entire page of technical references included in the Standard (section G). It is not clear why this is necessary, as the references are described as “beyond the scope of this Standard”.
Requirement 5.6 suggested wording revieion: Replace “may retroactively grant a temporary exemption” with “may grant a reactoactive temporary exemption”
The definition of the terms Frequency Excursion and Voltage Excursion were deleted. All references to these terms should now be lower case. Measures M4 and M5 continue to carry the prior wording and need to be revised to use lower case terms.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
Yes
The examples included in the Unofficial Comment Form are helpful in understanding the periodicity requirements associated with verifying the excitatation and volt/VAr control systems model and should be moved into an attachment in the standard. The standard is not as clear as the examples and the periodicities could be misinterpreted in the future without examples.
No
We appreciate the drafting team explaining their intent that only those units that meet the Compliance Registry Criteria are included. However, the language in the standard does not communicate this and the Statement of Compliance Registry Criteria has some ambiguous criteria that makes it unclear if a generator is applicable which is further discussed below. First, applicability section 4.2.4 of the standard discusses “any registered technically justified unit”. Units are not registered. Entities (i.e. companies) are registered. A Generation Owner certainly becomes registered

by the application of the Compliance Registry Criteria to its generating fleet but there is no publicly available list to which the applicable entities can refer to identify if a generating unit met the Compliance Registry Criteria. Thus, how would a Planning Coordinator know they could make a request? Second, the Compliance Registry Criteria includes units smaller than the 20 MVA unit threshold and 75 MVA plant threshold referenced by the drafting team. Blackstart Resources are included in the Compliance Registery Criteria and there is a statement that any generator that is material to the reliability of the Bulk Power System can be included. Blackstart Resources are usually very small and most likely do not meet the 5% capacity factor requirement established in other areas of the applicability section. We are guessing the drafting team did not intend to include these Blackstart units or any others units that don't meet the 20 MVA unit threshold and 75 MVA plant threshold established in Criteria III(c).1 and III(c).2 with the Appendix 5B – Statement of Compliance Registry Criteria. For clarity, the drafting team should modify applicability section 4.2.4 accordingly to eliminate units that are not intended to be included. Third, we disagree with the statement in the Background Information section of the comment form that the applicability section would have to explicitly identify units below the Compliance Registry Criteria. Because the standards applicability is not specifically limited to the Bulk Electric System, the statement in Requirement R5 that "any/plant not included in the Applicability" means that any unit that is considered part of the Bulk Power System could be requested by the Planning Coordinator. NERC enforces standards to the Bulk Power System which could include units below the Compliance Registry Criteria. They have made this clear in response to comments on CAN-0016 that the standards are enforced to the Bulk Power System. They stated clearly "According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS." While the Bulk Power System has never been clearly defined, we know that it is broader than the Bulk Electric System and could certainly include units below the Compliance Registry Criteria. One solution to more fully implement the expressed intent of the drafting team would be to limit the applicability section to the Bulk Electric System. Another would be to modify "any unit/plant not included in the Applicability" in Requirement R5 to "any unit/plant on the Bulk Electric System and not included in the Applicability". While the question posed by the drafting team here indicates that their intent was for the Planning Coordinator's technical justification to indicate that the actual unit response does not match the simulated response, there is nothing in the standard or requirement that indicates this intent. In fact, it only states the request from the Planning Coordinator must be technically justified. We suggest the drafting team modify Requirement R5 to make it clearer the actual system response does not match simulated response.
Yes
We continue to believe that this standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. This is the purpose of the FFT process that NERC initiated and FERC recently approved. Interestingly, within the approval order, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard and the problem with attempting to memorialize the cooperation that must occur between the Generator Owner and Transmission Planner to model the generator's excitation and volt/VAr control functions accurately. Requirement R3 allows a Generator Owner to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems can not be left unsolved. It should be struck. We are not convinced Requirement R4 is needed. The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of

applicable control system changes. For Requirement R5, there is no clarity for how soon the Generator Owner has to address the model concerns communicated by the Planning Coordinator. If the Generator Owner has the unit in its 10 year plan to test their generation fleet's control systems, they could simply communicate that plan which might be much longer than the Planning Coordinator intended. The drafting team needs to provide more guidance on whether the Generation Owner is expected to accelerate their plans for the unit in question by the Planning Coordinator and by how much. For Requirement R5, who decides if the request is technically justified? Could the Generator Owner simply choose not to respond because they do not believe the request is technically justified? In the Background Information section of the comments, the drafting team indicated that the "standard is drafted to provide the proper cost/benefit balance for performing generator verification". Since the summaries of field test results posted with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit and that does not even include opportunity costs from lost energy sales should the test cause the unit to trip, we believe it would be helpful for the drafting team to provide information on the cost/benefit that was discussed in the Background Information section of the comment form in the next posting. The response to our comments regarding consideration for early compliance from the last posting was not satisfactory. In our comments we stated that we appreciated the drafting team's consideration to allow for early compliance based on past tests. However, we stated concerns regarding how to demonstrate this compliance because a registered entity was not required to retain documentation and may not be able to prove they completed a test. The drafting team responded that demonstration of compliance was beyond the scope of the drafting team. While we agree demonstration of compliance for specific companies and situations are likely beyond the scope, demonstration of compliance in general is never beyond the scope. Drafting teams must write standard requirements with which can be complied. Given that the issue of evidence retention from before the effective date of the standard was one of the key subjects in the High-level review conducted by NERC for CAN-0008 recently at the request of the Trade Associations, we suggest the drafting team should consult the appropriate NERC subject matter experts to determine how to avoid these similar issues with this draft standard. Sections 4.2.1.2, 4.2.2.2, and 4.2.3.2 are confusing and potentially contradictory. First, these sections state that they apply to each generating plant/Facility greater than 100, 75 and 50 MVA respectively. Then, the second bullet under each of these sections applies to generating plant/Facility. How can there be a plant within a plant? With the first bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 50 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for individual generating units than section 4.2.1.1, 4.2.2.1, and 4.2.3.1 which apply to individual generating units. For example, 4.2.2.1 applies a 75 MVA threshold to an individual generating unit and then the first bullet of section 4.2.2.2 applies a 20 MVA unit threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. The NERC Glossary of Terms uses a generator as an example of a Facility. In the second bullet under each segment, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. The VRFs simply do not meet the NERC definitions for anything greater than Lower. Requirements R2 and R6 are written with Medium VRFs. All other requirements have Lower VRFs. Neither Requirement R2 nor R6 could be construed as affecting the electrical state or capability of the Bulk Electric System or the ability to monitor, control or restore it. Per NERC definition of Medium VRF, these are prerequisites for meeting a Medium VRF. For Requirement R1, the VRF justification for FERC Guideline 5 refers to the requirement having a high risk objective. This is not consistent with a Lower VRF. We agree with the Lower VRF and recommend removing the "high risk objective" language. All of the measurements use language that sounds like it is creating a new a requirement and is not consistent with language used in any other NERC standard. They all use "must include". It is more typical to use "shall demonstrate", "shall make available", etc. These measurements should be made consistent with other NERC standards. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. Some examples of the proof include dated postal receipts, dated confirmation of facsimile, etc. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. The

Compliance Enforcement Authority section is not the latest approved language being used by NERC. In the data retention section, there is no length of time given for how long a Generation Owner must retain information for Requirement R2 and its associated measurement. The High and Severe VSLs for Requirement R5 need to be updated. They still refer to Subparts 5.2 and 5.3. The Subparts have been changed to a bulleted list which means they are options. Thus, missing one and meeting the other is full compliance and not partial compliance as the VSLs suggest. We suggest the drafting team write a brief paragraph at the beginning of the Reference section to explain the inclusion of the References. Currently, it states that those references contain technical information that is out of scope of the standard. If so, what is the purpose of including them? We are not against including them but just believe a short explanation for their inclusion is necessary. The verification periodicity for row 3 in Attachment 1 needs to be updated from 356 days to 365 days. Furthermore, the drafting team should consider using a year to account for leap years. Otherwise, every four years we are shifting the compliance date up by one calendar day.
No
This requirement will essentially be redundant with standards MOD-026 and MOD-027. MOD-026 already requires the Generator Owner to verify its excitation and volt/VAr control systems. MOD-027 already requires the Generator Owner to verify its frequency response and its turbine/governor, load control and active power/frequency control models.
No
It is not clear to us why this requirement is needed given the many tariffs that already exist to govern interconnection requests. These tariffs already have well established facility connection requirements. If the requirement persists, we believe it actually belongs in the FAC-001 standard which establishes facility connection requirements for new facilities including generators. While we believe that this requirement is probably technically achievable in most cases, there should be exceptions available. It looks like Part 5.3 will allow the Transmission Planner to offer these exceptions. However, this does not consider that the Transmission Planner in many cases (especially organized markets) is not the entity evaluating interconnection requests. Thus, the Planning Coordinator should be allowed to grant exceptions in those situations as well. The need to supply the bases for the estimate in Part 4.2 is not clear, offers no reliability benefit and is administrative in nature. Of the three bases listed, (experience, actual event histories, or sound engineering judgment) what will the RC, PC, TOP, or TP do with the bases? Will they decide the bases are invalid and substitute their own judgment? If so, what is the purpose of getting an estimate from the Generation Owner anyway? It appears to be a documentation requirement that offers no reliability benefit or even information for which the recipient of the information could take action.
Because NERC has made clear that standards are enforced against the BPS and not the BES, the applicability section should be modified to state clearly that it applies to Facilities that are part of the BES. Otherwise small generators that do not affect reliability could be impacted by these standards. NERC enforcement has made this clear in response to comments on CAN-0016 that the CIP-001 standard applied only to the BES. They stated clearly: “According to Section 39 of the Energy Policy Act of 2005, NERC defines the Interconnected Power Grid as the Bulk Power System. Unless otherwise restricted by a standard, it is applicable to the BPS.” Use of “new or existing” as a description for the generators in Requirements R1, R2 and R5 is confusing. What exactly constitutes new and why is it relevant? The requirements are performance requirements that apply to in-service generators so how does new help explain this further? The footnote in Requirement R5 only further confuses the situation since it is not included in Requirements R1 and R2. Part of the confusion likely centers around Requirement R5 applying to maintaining new generators frequency and voltage excursion performance as well as designing and building it. If “maintain” was removed from Requirement R5, we believe “new” could be removed from Requirement R1 and R2 and they essentially become the maintenance requirements. Furthermore, “new and existing” is not used consistently within other requirements such as Requirement R4. It is not obvious why it would not apply to Requirement R4 it if applies to Requirements R1 and R2. Neither Requirement R1 nor R2 state within the main body of the requirement that the Parts are intended to be exceptions to the requirement. For clarity, there should be a statement (i.e. except when the Parts 1.1 and 1.2 are met) within the requirement that makes this clear. For Requirements R1 and R2, it is not clear if the sub-parts are the only reasons that allow for exceptions if other equipment limitations exceptions are allowed. Other equipment limitations should be allowed, and these requirements should be clarified to allow them. As written, Requirement R5 appears to be assumed to apply to a new generator in perpetuity. We draw this

conclusion from the inclusion of "maintain" in the requirement. We think it makes more sense to have this requirement apply only to designing and building a new unit and then have the requirements that apply to existing units apply to the maintenance of the new units once they are established. The standard does not appear to allow "new" generating units to have frequency and voltage excursion performance limited by equipment. It should allow "new" equipment as it experiences normal wear and tear as well as damage for any other reasons to document its equipment limited frequency and voltage performance and communicate it similar to Requirements R1 through R3. Otherwise, a Geneator Operator with a "new" generator that has damaged equipment will be forced between operating the unit in a limited manner providing reliability support to the BES and possibly in violation of this standard or taking a forced outage to avoid violating the standard and experiencing escalated penalties for knowingly violating the standard. We do not believe that Reliability Coordinator is the proper entity to grant a temporary exemption in Part 5.6. Rather, it is the Planning Coordinator that should grant the exemption. Furthermore, this is not consistent with other requirements such as Parts 2.1 and 2.1.1 that specify the Transmission Planner grant the exemption. Of course, Part 5.6 would not be necessary if Requirement R5 did not deal with maintaining the unit and allowed the other requirements that apply to existing units to address maintenance. We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary.
Individual
Dale Fredricksen
We Energies
Yes
add more explicit detail to the Table to indicate that the exemption may apply to some wind farms, solar resources, etc.
No
We strongly oppose this Requirement as unnecessary to the reliability of the BES. Requirement R5 should be removed from the draft Standard. Either the standard is applicable to a generating unit, or it is not. A generating unit that is not covered in the Applicability section should be exempt from the requirements of this standard unless the standard is revised under the approved standards development process. The SDT's assurances to the contrary are not sufficient. This requirement will allow the possibility of sweeping more generators into the requirements than is necessary.
a. In Section A3. reference is made to Bulk Electric System (BES) reliability. Then, in Section A4, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. b. In Requirement R1, instead of the TP providing "instructions", the standard should require the TP to simply "provide" the model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. c. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple generating units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the need to develop these equivalent models. The requirement should be more flexible to allow the GO the option to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate

model. d. In R2.1.1, the GO is required to provide documentation that the generator model response matches the recorded response for a voltage excursion. Since the GO often does not have the capability to run dynamic studies, how will it obtain the “model response” for comparing to the recorded response? We suggest that this requirement be modified to require that the GO “provide the recorded response for a voltage excursion”. As presently written, R2.1.1. can only be required of the TP. Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the voltage data as required in R2.1.1. There needs to be a recognition that the Transmission Planner and Generator Owner will need to work cooperatively on this. The goal is good, but this standard is not nearly developed enough to be a useful standard.
No
It is very difficult to estimate generator performance during frequency or voltage excursions, especially frequency, and the best efforts to provide an estimate may not provide a meaningful result. It is proposed that the TO or TP could achieve the objective better by tracking transmission system voltage/frequency events that could have resulted in abnormal voltages at generating stations, and work cooperatively with the GO informally to determine the generator performance.
a. Most generator voltage relaying is supplied from generator voltage transformers on the low-voltage side of the generator step-up transformer (GSU). It is necessary to provide the information needed for the Generator Owner to relate relay settings on the low-side of the GSU to the No Trip characteristic in Attachment 2, which is based on voltages on the GSU high-side. b. In Attachment 2, please clarify whether the No Trip zone includes the lines, similar to what was done in Attachment 1.
Individual
Joe Petaski
Manitoba Hydro
No
Manitoba Hydro agrees with the concept for manually switched capacitor banks but disagrees for automatic capacitor banks. A model should be required for automatic capacitor banks.
Yes
The implementation plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.
Yes
Yes
Manitoba Hydro is voting negative for the following reasons: 1 - Implementation time frames - the implementation plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. 2 - R5 ‘walk down’ - the requirement of a ‘walk down’ of equipment in R5 is unclear. Manitoba Hydro suggests that the wording be revised to ‘based on an onsite review of the equipment.’ 3 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to “provide other evidence” if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what ‘other evidence’, besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. Manitoba Hydro also suggests that synchronous condensers be included in MOD-026.
No
More detail is required in R4 to ensure that the Transmission Planner can model behavior before and after the disturbance. Information should be provided on how long the unit should take to ramp back to full power following a voltage or frequency excursion that doesn’t cause the unit to trip.
Yes

Manitoba Hydro is voting negative for the following reasons: 1 - R1 - the facility interconnection document required through FAC-001 should supersede Attachment 1 in order to best address local area issues. R1 should be revised to specify this. 2 - NERC IVGTF Task Force Document - the SDT should consider the recommendations from the NERC IVGTF Task Force 1.3 document. Specifically, the recommendations regarding clarifying the potential coordination issues between TPL-001 and PRC-024, clearly defining performance requirements for unbalanced and balanced faults, and defining the performance required during and after disturbances and making clear and unambiguous statements as to what remaining “connected” entails (i.e. how much real power is expected to be delivered post disturbance and how long until the normal pre-disturbance power can delivered) should be considered. 3 - Low Voltage Ride Through clarification - more information is required on the low voltage ride through curve. The GO should be required to provide unit outputs and ramp rates for the different voltage transitions and levels on the ride-through curve. 4 - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to “provide other evidence” if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what ‘other evidence’, besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
No
Attachment 1 is confusing, in 2 aspects: a. Attachment 1 starts off with a heading and a blue-shaded page in which the verification periodicity requirements are clearly stated. It is not clear whether or not the 3 by 12 table that follows is a part of Attachment 1 and whose content is part of the periodicity requirements that must be complied with. b. This question (Q2) suggests that guidance is provided on the periodicity aspects of Attachment 1. Is the content in the 3x12 table meant to be guidance? If so, it should be clearly stated so that it does not need to be complied with. If not, where and what is the guidance that the SDT refers to?
Yes
Yes
a. Requirement R2.1: We continue to disagree with the phrase “models acceptable to the Transmission Planners” as it is a potential source of dispute between the TP and the GO. Requirement R1 already asks the TP to provide instructions and model data to its requesting GO but makes no reference to “acceptability”. To avoid potential disputes, we suggest that R2.1 be reworded to: R2.1. Perform verifications using one or more models provided by the Transmission Planner in R1, that include(s) the following information: ….. b. We continue to disagree with Parts R6.1 to R6.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model, especially if such devices are new for which there are no previous simulations to benchmark with. A computer model may fail to initialize due to reasons other than inaccuracy in the submitted excitation control system and plant volt/var control function model itself, and a no-disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. System damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three parts. We suggest this requirement be removed.
No
As indicated in our previous comment, we do not support having a requirement to obtain such an

estimate. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2 and Requirement R3 and the information already received, a TP can apply the following relevant assumptions to its planning studies: i. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; ii. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be more valid than applying the conservative assumption "b" above. We cannot envisage a Transmission Planner to use this additional information if this information cannot be ascertained to be more valid. In short, we do not believe provision of this estimate will provide any more valid assessment of a generator's expected performance than a TP's conservative assumptions drawn from available information already provided by the GO and Attachments 1 and 2. The estimate does not provide any reliability benefit at all. We suggest the SDT remove this requirement altogether.
We believe this requirement is achievable for most cases. However, provision should be given to the Generator Owners which for specific technical reasons are unable to design a generating unit to comply with the requirements. As worded, R5 does not contain this provision. We therefore suggest that R5 be appended with ", or provide the technical reasons why this is not achieveable" after "the following conditions and exceptions".
a. Requirement R1: We believe the words "or generating plant" are missing at the end of R1 since the requirement addresses frequency protection relay settings for new or existing generating unit and generating plant. b. Requirement 4: In the last posting, we commented that: "We do not support the requirement to provide an estimate of the performance of the units during frequency and voltage excursions. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3, the TPs can apply the following relevant assumptions: (i) For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; (ii) For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? The SDT responded that "The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability." We do not agree that removing the 20% increment part goes far enough to achieve a good quality standard. In our view, based in argument put forth in our previous comments, the whole requirement does not add any value to reliability. We again suggest the SDT to remove this requirement altogether." c. Requirement R4.1, last sentence "If the Generator Owner expects the existing unit, generating plant will remain connected.....". We believe the "," before "generating plant" should read "or". d. The proposed implementation plan for both standards conflicts with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of the sentences in Section A5, after "following applicable regulatory approval", of the two standards to the following effect: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."
Group

Pepco Holdings Inc. & Affiliates
David Thorne
No comment
No comment
No comment
No comment
Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term "bulk power system." This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term "bulk power system" (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term "Bulk Power System" as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term "Bulk Power System" defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of "Bulk Electric System" (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term "bulk power system" and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition.
Yes
Agree in principle with attempting to quantify the ability of the unit (including affect on plant auxiliary systems) to remain connected during voltage and frequency excursions. However, the present wording of this requirement may not result in sufficient information to fully model the performance of the unit in dynamic studies. It may be more constructive to request a modified set of voltage and frequency ride through curves (similar to Attachments 1 & 2) that represent the Generator Owner's best estimate of a no trip zone for each unit, taking into account the performance of plant auxiliary systems, as well as any other protection / control setting, or operational limitation, that would prevent the unit from remaining on line within the no-trip zone as defined in Attachments 1 & 2. This would provide the Transmission Planner with sufficient information to fully model the anticipated performance of the unit in their dynamic studies.
Yes
Yes, it is possible to design a new facility to operate within the requirements identified in this standard. However, it may require specification of equipment with higher than normal overvoltage capabilities. Also, significant analyses would have to be conducted on the behavior of plant control systems (exciter controls, boiler controls, etc.), as well as equipment connected to auxiliary busses (including low voltage motor contactors) to ensure that all systems are designed with appropriate ride-through capabilities.
1) If it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with close in three phase faults, then it is equally as important to have them remain on-line for single line to ground faults, which are much more common. During a phase to ground fault at the point of interconnection the faulted phase voltage collapses to zero but the unfaulted RMS phase to ground voltages could rise as high as 80% of the RMS line to line voltage for an effectively grounded system (with a coefficient of grounding = 80%). This is well in excess of the 1.2 p.u. overvoltage requirement presently shown in Attachment 2. As such, for the unit to ride through phase to ground faults at the point of interconnection then the short time 1.2 p.u. overvoltage threshold at the point of interconnection needs to be raised above 0.8 x 1.73 = 1.38 p.u.. In summary, the overvoltage portion of the curve in Attachment 2 should be modified to require the unit to stay

connected with a 138% phase to ground overvoltage appearing at the point of interconnection for up to the expected clearing time of a Zone 1 phase to ground fault. 2) The standard should make clear whether the no-trip zone shown in Attachments 1 and 2 includes the boundary curves themselves. 3) To add clarity and avoid confusion, the ordinate of the graph in Attachment 2 should be labeled Per-unit RMS Voltage Measured at the Point of Interconnection. 4) The current language in Item #1 of the “Voltage Ride-Through Curve Clarifications,” which appears on the last page of the standard, may cause problems for generator interconnections on the 500kV system. Most transmission Planners use “nominal” transmission system voltage levels as the “base voltage” in their system models. These are the same “nominal” system voltages specified in ANSI C84.1. In most cases, C84.1 shows the maximum allowable system voltage as 105% of nominal, with the exception of 500kV. For 500kV systems the maximum system voltage is 550kV, and it is routine to operate the transmission system above 525kV (105% of nominal). If the “base voltage” at the point of interconnection used in planning studies is 500kV but the system is normally operated above 105%, then the generation protective systems must be capable of maintaining operation with the continuous voltage at the point of interconnection above 105% of “nominal” (at least for 500kV systems). This being the case the voltage base in Attachment 2 for 500kV systems will by necessity have to be something other the “nominal base voltage” used by the Transmission Planner in their system models. Perhaps this could be addressed by re-wording Item #1 to read “1. The per unit voltage base for these curves is to be specified by the Transmission Planner at the point of interconnection to the Bulk Electric System (BES).” By removing the reference to “the base voltage used in the system models by the Transmission Planner” it eliminates the conflict mentioned above. On the other hand it now requires the Transmission Planner to provide this “other than nominal base voltage for 500kV systems” to the Generator Owners. 5) The word “crest” should be removed from Item #5 of the “Voltage Ride-Through Curve Clarifications,” which appears on the last page of the standard . The voltages referred to in this standard are all per-unit “RMS” voltages, not “peak” or “crest” voltages. 6) Typically unit connected generator protection packages, which include frequency and voltage protective elements, are supplied by voltage transformers connected on the terminals of the generator rather than on the high side of the generator step-up (GSU) transformer. For frequency elements, the frequency at the terminals of the generator is the same as on the high side of the GSU transformer. So comparison of frequency protective element set points can be made directly with Attachment 1. However, this is not true for voltage. The generator terminal voltage could be higher, or lower, than the system voltage on the high side of the GSU transformer depending on the voltage drop across the transformer, which varies depending on the generator real power output and whether the generator is supplying or absorbing reactive power. Since this standard requires the generation to remain connected for specific voltage criteria as measured at the point of interconnection, but the voltage sensing protection is connected to the generator terminals, some technical guidance (with specific examples) must be provided to allow the Generator Owner to properly translate these voltage criteria to the voltages seen by the protective relays on the terminals of the generator. Otherwise an incorrect evaluation may result. It is recommended that a Technical Reference Document similar to the “Power Plant and Transmission System Protection Coordination” document developed by the NERC System Protection and Control Subcommittee be produced, or the above mentioned document revised, to provide illustrative examples of how to apply the Attachment 2 POI voltage criteria to voltage sensing protective elements connected to the terminals of the generator.
Individual
Kathleen Goodman
ISO New England Inc
No
While some plants may not have excitation systems, per se, they can have complex reactive coordination controllers, whose settings and functions should be tested and verified.
Yes
No
No, Footnote 4 in the Applicability Section implies comparing simulated unit or plant response to a dynamic system event. This is not acceptable, verifying the model only after an event as called for is completely counter to increasing system reliability. In addition, analyzing an event and determining that a particular generating unit model is inaccurate will prove difficult in practice. We feel the

applicability section needs further revision, by requiring only generators above 100 MVA with unit capacity factors above 5 % to test, about 30% of the installed generation in New England does not require model validation. We believe this is a large portion of the generation that is being exempted. Additionally, the low capacity factor units will likely be running during the periods when the system is being stressed the most and reliable operation is being most challenged. We realize that a model for the generators and associated equipment is supplied in accordance with MOD-012 but we feel the accuracy of such models may be limited and a higher percentage of generator validation is required. Footnote 4 should be changed to allow verification of generator models not required under the applicability to be at the discretion of the Transmission Planner. In some areas of the system, generator models have a considerable impact on dynamic performance and model accuracy is critical.
Yes
While we support the clarifcation of capacity factor, please note our concerns with an exclusion for units with less than a five percent capacity factor that are included with question 3.
We suggest that the language for R4 be made more clear and state as follows. “R4. Each Generator Owner shall provide revised model data or plans to perform model verification5 (in accordance with Requirement R2) to its Transmission Planner 180 calendar days prior to making changes to the excitation control system and plant volt/var control function that alter the equipment response6characteristic. The way the language is currently written, the generator merely has to provide its plans for model verification. This means that 6 months after a change has been made, the correct data still may not have been made available to the Transmission Planning. This could have a significant impact on reliability. The suggested language would be in line with FERC approved language that is currently part of ISO Tariffs.
Yes
Yes
The exception in 5.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024 without exception. Simultaneous loss of 10 percent of the generators at a number of installations could introduce severe reliability concerns. This standard appears to allow loopholes which undermine reliability.
ISO New England has comments on Requirement R2 and R3: R2 Although the time duration is acceptable ISO-NE does not agree with the band shown. The band is shown as 0.95 p.u to 1.05 p.u at the point of interconnection. Parts of the New England system have not been designed to maintain steady state operation within this band. The band needs to be expanded to 0.90 pu to 1.05 pu. We also believe there are a number of other parts of the system outside of New England which would have similar concerns. Failure to make this change means that it is acceptable for generators to trip during steady state operation of the system on “low” voltage. Unanticipated tripping of generators under steady state conditions could lead to significant reliability concerns on the system. R3 The ISO would like to reiterate its previous comment that R3 is a significant concern. In the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the “No Trip Zone”, there is no requirement to correct the issue. Instead, the generator must only document the limitation. This completely undermines the intent of this standard. There is no point to setting undervoltage relays to meet the curve if other equipment is still going to trip the plant. This standard appears to simply documenting system concerns rather than identifying and correcting them.
Individual
Keira Kazmerski
Xcel Energy
Yes
Yes
Yes

Yes
Yes
We agree that the current wording (which removes the requirement to provide a probability of ride through) is an adequate means of achieving the reliability goal.
Yes
We believe the requirement is technically achievable, but question whether the additional cost to design and build plants to meet this goal is the most effective way to spend money to increase grid reliability.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Yes
Yes
ATC recommends that the SDT give consideration to the following: 1. In Requirements, R1, bullet 2 – change the wording to be more similar to bullet 1, “obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations”. Software manaufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets, allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. 2. In Event Triggering Verification Table, Item 6, Cell 1 – fix typographical error of “. . . system event did not "did not" match . . .”
Yes
Yes
ATC recommends the SDT give consideration to the following: 1. In Requirements R2 – the text refers to “non-protection system equipment” but this terminology is not defined. ATC recommends that the SDT provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. 2. In Requirements, R3 – ATC recommends that the SDT add the requirement that the GO provides the expected duration of the limitation, if it is known.
Group
Florida Municipal Power Agency
Frank Gaffney
The applicability refers to the “bulk power system”, e.g., “4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system”. The term “bulk-power system” should not be used in the standards as it is ambiguous and should be replaced

with “Bulk Electric System” We do not understand how the Applicability of 4.2.1.2 means. We suggest making the language clearer. R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualfied?
R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the “grandfathering” of existing equipment lmimtations should still be in place. R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst abstains on the MOD-026-1 ballot and offers the following comments for consideration: 1. Facilities a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. 2. Requirement R1 a. For the purposes of NERC standards, “bullets points” are to be considered “OR” statement. ReliabilityFirst believes all the “bullets points” in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) 3. Requirement R5 a. ReliabilityFirst is unclear on the meaning of the term “walk down of the equipment” in the second bullet? ReliabilityFirst request further clarification of the term “walk down of the equipment?” 4. Requirement R6 a. ReliabilityFirst requests further clarification on the term “initializes” as referenced in Subpart 6.1. Is this in the context of excitation control system and plant volt/var control function model initialization within a PSSE application? 5. Section G. References a. ReliabilityFirst recommends removing the references in Reference Section G and place it into a reference type document. Even though this good information, it is not needed in a Reliability Standard. 6. VSL Requirement R2 a. Requirement R2 contains a sub-part 2.2 which is not mentioned in the corresponding Violation Severity Level (VSL). ReliabilityFirst recommends including a VSL covering Subpart 2.2. Here is an example of a “lower” VSL: “For plants that are comprised of units that have a gross nameplate rating of less than 20 MVA in Requirement R2, Subpart 2.2, the Generator provided the Transmission Planner verified models, using plant aggregate model(s), that omitted one of the six Parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.” 7. VSL Requirement R5 a. The VSL for “High” and “Severe” mention Subparts 5.2 and 5.3 though there are no associated subparts referenced in Requirement R5 (there are only 2 bullet points). ReliabilityFirst recommends removing the references to Subparts 5.2 and 5.3. 8. VSL Requirement R6 a. R6 requires the Transmission Planners to “…notify the Generator Owner within 90 calendar days… “, while the corresponding VSL states “The Transmission Planner provided a written response to the Generator Owner indicating…” Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," ReliabilityFirst recommends the following as an example of the “Lower” VSL: “The Transmission Planner notified the Generator Owner indicating whether the model is useable or not useable;

including a technical description if the model is not useable, more than 90 calendar days but less than 120 calendar days of receiving verified model information. (R6)”
ReliabilityFirst votes in the affirmative for the the PRC-024-1 standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Requirement R5 and associated Subpart 5.1 a. ReliabilityFirst believes there is a potential conflict and seeks clarification on the choice of words between Requirement R5 and associated Subparts 5.1 and 5.1.1. Requirement R5 begins by stating “Each Generator Owner shall design, build, and maintain its new unit or new generating plant…” which lends itself more to the “planning” type stages while Subpart 5.1 states “When the generating unit or generating plant is operating at or above the minimum sustainable generation threshold” which lends itself to actual “operation” of the unit. ReliabilityFirst questions how the conditions in Subpart 5.1 and 5.1.1 can be utilized if the actual “operation” of the unit has yet to be observed since Requirement R5 is dealing with the design stages of a new unit? 2. Requirement R6 a. ReliabilityFirst request further clarity regarding whether the parenthetical, “(that monitors or models the associated unit),” is associated with all the requesting entities listed in Requirement R6 (RC, PC, TOP, and TP) or just the TP. 3. VSL Requirement R5 a. Requirement R5 states “Each Generator Owner shall design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion.” The VSL states “The Generator Owner’s generator tripped due to a Frequency Excursion within the no-trip parameters set forth in attachment 1”. Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement," the language in the requirement is not consistent with the associated VSL. It is not a violation of Requirement R5 if the generator tripped offline within the no-trip parameters, rather it is a violation if the GO failed to design, build, and maintain its new unit or new generating plant so that it will not trip due to a frequency excursion or voltage excursion. ReliabilityFirst recommends the following language for the “High” VSL, “The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a frequency excursion within the no-trip parameters set forth in Attachment 1. OR The Generator Owner failed to design, build, and maintain its new unit or new generating plant so that it will not trip during a voltage excursion within the no-trip parameters set forth in Attachment 1. b. ReliabilityFirst also noted there is no mention of the Subparts 1.1 through 1.7 in the VSL (ReliabilityFirst understands that these are “Conditions and Exceptions” but they should somehow be incorporated into the VSLs.
Individual
Thad Ness
American Electric Power
Yes
No
The tiered approach of MOD-026 Attachment 1 are both unorganized and more complex than necessary, and is confusing as a result. The same approach could be communicated in a more succinct format. In addition, there is content within the attachment that is not mentioned anywhere else in the standard, such as the initial verification of new units and dealing with equivalent units at the same physical location.
Yes
The team might wish to consider if the Transmission Planner should also be included in the applicable facilities 4.2.4 and 5. Point of clarification: one does not “register” units, rather entities are registered for NERC functions.
For section 4.2 we suggest the term “bulk power system” be replaced with “Bulk Electric System”. BES is currently being defined, while bulk power system currently does not have a definition and thus is ambiguous. In the second bullet of 4.2.1.2, one of the words “comprised” or “consisting” needs to be removed as they are redundant. Also, we are confused by the bullets in 4.2.1.2 which should be re-worded to clarify the intent. For example, would diesel generators at a larger facility be in scope of

this requirement? Furthermore, the qualifier between the two bullets should be “or” rather than “and”. For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year. Throughout the standard, “generator excitation control system and plant volt/var control function model” should have an “or” rather than an “and”. The second footnote in requirement 4 could be interpreted to be all-inclusive. Please check the numbering of all footnotes and the pages that those footnotes reference. References should only be made to footnotes on the same page as the referring number.
Yes
AEP agrees with this approach for Attachment 1 only. We also have the following comments about the reference to Attachment 2 in R4. The reliability advantage to be gained from the inclusion of Attachment 2 is unclear, unprecedented and potentially costly. With respect to Attachment 1, any information that a GO can provide about a potential for their unit to trip within the no-trip zone of Attachment 1 will assist the Planning Coordinator in devising a UFLS program for their area, which they are obligated to do under PRC-006-1. A successfully designed UFLS program depends on knowing whether or not generation would trip prior to operation of all stages of UFLS. If it is known that a generator could trip prior to all stages of UFLS, apart from protection settings that would be reported to them under R1 of this standard, the PC ought to know that. Of course, we understand that a GO would not be held accountable under R4 for unknown factors that may result in tripping of their unit within the no-trip zone of Attachment 1. Attachment 1 should be referenced because it would be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the coordination that should take place between UFLS and generation tripping apart from Attachment 1. We also believe reference to Attachment 1 is necessary for consistency in the application of R4 throughout an interconnection. We therefore conclude that it is desirable for overall reliability purposes to reference Attachment 1 in R4. We also point out that curves of the nature of those in Attachment 1 have long existed as guidelines for generation performance during frequency excursions in each of the reliability regions. GOs are familiar with these types of curves, and generating units have been designed with these guidelines in mind. With respect to Attachment 2 being referenced in R4, the reliability advantage is not as clear, but we ask the SDT to consider again that it may be difficult for the TP to come up with simulation results that would adequately convey in a comprehensive fashion the possible voltage excursion events that a generating unit may be subject to, and for which it may be desirable to know whether or not a given generating unit would be able to ride through that disturbance. Reference to Attachment 2 may be desirable for, again, consistency in the application of R4 throughout an interconnection. However, in contrast to frequency, voltage is a local quantity and so it is not as critical to system reliability that GOs report voltage excursion trips within the no-trip zone of Attachment 2. The translation of the no-trip zone of Attachment 2 to internal generating plant voltages that would need to be determined is not straightforward, though that translation would need to be made by a GO regardless of whether they would receive point-of-interconnection voltage simulations from a TP or be directed to Attachment 2. We conclude that reference to Attachment 2 in R4 may have reliability benefits that the SDT may want to consider, but we do not believe reference to Attachment 2 is as essential as reference to Attachment 1. If the SDT did not include reference to Attachment 2, that should not have a bearing on the reference to Attachment 1. We assert that, because of the different characteristics of frequency and voltage, it would not be inconsistent to reference Attachment 1 but not Attachment 2.
No
AEP believes that the requirement for new units and plants to not trip within the no-trip zone of Attachment 1 is reasonable, and has precedence in existing reliability region guidelines. To not trip within the no-trip zone of the Attachment 2 is another matter. AEP believes Attachment 2 is inappropriate as a requirement on conventional generation for the following reasons: (1) It has not been found necessary to impose such a requirement as Attachment 2 on conventional generation in the past and we question why this should be proposed now. The appearance of such graphs seems to have been in response to the performance of wind farms that tripped off-line by protective relays when minor fault disturbances occurred on the transmission system. Attachment 2 may thus be an appropriate requirement for wind turbine generators and other non-conventional generation. We ask the SDT why such a requirement now needs to be imposed on conventional generation. If this is being done solely for the standard to appear technology neutral, it does not remove the fact that a new, unnecessary, and possibly onerous requirement is being imposed. (2) Application of Attachment 2 to

conventional generation is not straightforward because of the need to translate point-of-interconnection voltage to plant or unit internal voltage, particularly in the time period following fault removal (.15 seconds). Conventional synchronous generators have a substantial capability to control the voltage they are subjected to during a system disturbance (unlike most wind farms) and whose critical auxiliary systems are usually (and should be) served from the generator bus (low side of GSU) and are thus shielded to some degree by the GSU impedance from voltage excursions on the transmission system. (3) Back in 2005, FERC Order 661-A contained a requirement for wind farms to ride through point-of-interconnection faults up to 9 cycles as determined by the actual fault clearing time at the interconnection station. The final order was thought to be sufficient to ensure wind farm fault ride-through by intervening parties including NERC and AWEA without the need for a graph along the lines of Attachment 2. Justification for the content of the final order was that all generation would be treated equitably. Why does the SDT now think it necessary to impose Attachment 2 on new generation? It would seem that deference to TPL standards for the types of transmission system disturbances where stability should be maintained should continue to be an acceptable ride-through criterion for all types of generation. Reference to Attachment 2 in R5 should thus be replaced by a requirement for all generation to ride through normally cleared 3-phase or unbalanced faults at the POI not to exceed 9 cycles. (4) We do not know the incremental cost to comply with Attachment 2 under R5; however, we believe that it could be very costly to design and build synchronous generating units that would, with a high degree of confidence, remain on-line for any and all disturbances whose POI voltage falls within the no-trip zone. Attachment 2 would also be a new requirement without historical precedent and the SDT has not stated how reliability would be improved. With uncertain reliability benefits and uncertain and potentially high incremental costs to comply, we do not think the SDT is in a position to impose this requirement. For these reasons, we believe that reference to Attachment 2 in R5 should be removed.
R2 is very “wordy”, essentially a single run-on sentence which references yet additional material in its two footnotes, making it difficult to follow. This could be made more clear with the usage of bulleted items. R2.1.1 through R2.1.4 could be and perhaps should be R2.2 through R2.5. R3: We recommend adding “known” to R3 such as “…shall document each known equipment limitation…” to make clear that a GO is not responsible for a cause they are not aware of. R3: The second point under R3 causes the limitation to expire with rating increases. Is a 10 percent or more rating increase a realistic scenario and common enough to justify attention? 10 percent seems arbitrary and this provision could pose a hindrance to rating increases that may supply other reliability benefits. It may be advisable to remove this point. R4.1 should include the Planning Coordinator in addition to the TP because the PC is responsible for UFLS coordination and assessment in PRC-006-1. R5.2 should be removed because of its obvious partiality toward wind farms. R5.6 needs to include coordination with the Planning Coordinator because of the PC’s responsibilities with respect to automatic UFLS. This should also perhaps include coordination with the Transmission Planner for exceptions on voltage excursion ride-through.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes
We agree that there is no useful purpose served by requiring a GO to validate voltage performance on those generators where an active voltage regulator is not used. The modeling of passive capacitor and reactor banks has been established for many years and does not likely need any improvement.
Yes
We support the efforts by all project teams to clearly define the implementation and subsequent periodic evaluation time frames – as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC’s Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-026-1, we believe that the proposed intervals are sufficient to perform the voltage performance model validations; however they are initiated.
No
Ingleside Cogeneration believes that Item 4.2.4 under the “Applicability” section was intended to capture the concept that a Planning Coordinator’s request for additional information is limited to NERC-registered units. However, the language of requirement R5 will predominate, and it reads as

follows: “R5. Each Generator Owner shall provide a written response to its Planning Coordinator,within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant NOT INCLUDED IN THE APPLICABILITY (our emphasis) that includes one of the following” This provides clear instruction that the entire Applicability section may be ignored – even Item 4.2.4. We suggest the following language instead: “R5. Each Generator Owner shall provide a written response to its Planning Coordinator,within 90 calendar days following receipt of a technically justified1 request from the Planning Coordinator to perform a model review of any NERC-REGISTERED unit/plant not included in the Appliability that includes one of the following” 1 Technical justification is achieved by demonstrating that the simulated unit or plant response does not match the measured unit or plant response Please notice that we also added the footnote under Item 4.2.4 to R5. Although this update is essentially a duplicate, it leaves no doubt to the limits of an exceptional model validation request by the Planning Coordinator. Secondly, MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. We believe that the Planning Coordinator must first engage these entities before issuing such a request to the GO.
Yes
Ingleside Cogeneration strongly agrees with the SDT’s use of the capacity factor calculation used in the GADS system. It is always important to establish links to time-tested parameters – and eliminating any possibility that some other calculation is used.
1. Ingleside Cogeneration LP cannot agree with the change in the applicability section of MOD-026-1, which references generation connected to the “bulk power system” rather than the NERC-defined term “Bulk Electric System”. This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the disrection of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 “Definition of the Bulk Electric System” which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities. 2. What could possibly be a technical justicfication for including generators below that included in the Applicability Section. Without this in the Standard, it leaves it open to whatever the PC is inlinded to do. If you have a “catch all” requirement, you need to have a specific set of technical requirements to limit the PC’s descretiion. 3. Registered Entities below the individual unit thresholds of 100MVA, 75MVA, and 50MVA do not need to be modeled unless there is technical justification. This is a significant burden on small generators. Small generators should only be required to provide model verfication where the PC can show justification through a set of criteria.
No
Ingleside Cogeneration believes that this is an open-ended requirement that allows multiple planning and operations entities – not just Transmission Planners – to require complex assessments completely at their discretion. There is no allowance for the availability of GO resources nor any need for the requestor to provide a reliability justification. Furthermore, we would like to point out that the modeling validation requirements of MOD-027-1 (frequency) and MOD-026-1 (voltage) must, by definition, include the impact of protective relay settings. This means that a need for an estimate of performance is not necessary as real performance data will always be available. In addition, these Standards already allow recourse for a re-validation if Transmission Planners cannot reconcile their models with actual generator performance.
Yes
In our view, the time frame allotted to accommodate PRC-024-1’s frequency and voltage ride-through specifications for new generating facilities is reasonable.
Ingleside Cogeneration LP fully supports the goal to standardize voltage and frequency ride-through settings. In addition, we recognize the benefit to provide accurate generator modeling information and perform regular performance validations to system planners. However, such activities come at a price and compete for the same resources needed to support BES reliability in other ways. Furthermore, there is a cost to develop new PRC-024-1 compliant generation technologies – or to harden existing ones. This may improve reliability over the longer term, but could delay or even rule out the deployment of promising capabilities early on. These are all considerations that we know that the project team is aware of, but we will continue to point out the hidden costs of compliance

wherever we believe that a justification of its advantages is not immediately obvious.
Group
Tennessee Valley Authority GO/GOP
David Thompson
Yes
Yes
Yes
Yes
Yes
No
There are specific areas within the no-trip zone curves in attachments 1 & 2 that would violate nuclear safety limits, which are controlled by the NRC. Also, the turbines of large steam-turbine units may be exposed to unsafe operating conditions within the no-trip zone of the frequency curve.
Group
Puget Sound Energy
Tom Flynn
Yes
Yes
Yes
Yes
None
Yes
No
Steam units appear to have very tight frequency requirements, and the damage is cumulative. In order to protect the prime mover, after several under frequency operations the units may need to immediately trip offline.
Our existing units capabilities are outside those required in the frequency attachment.
Group
Dominion
Mike Garton
Yes
Yes

Yes
Yes
Individual
Brad Jones
Luminant Energy
Yes
Yes
Yes
No
Appendix F of the GADS Data reporting has two Capacity Factor calculations (Gross and Net). The standard should specify Net Capacity Factor.
No
An estimate of the time that a unit would remain on-line during or following a voltage or frequency event described by a Transmission Planner would be difficult if not impossible considering the complexity of the auxiliary system and would result in little value to the Transmission Planner. There is no known methodology to provide a consistent estimation or calculation of the value. Luminant recommends that the requirement be removed from the standard.
No
Although this requirement may be achieveable, it is highly probably that as the unit ages, components will begin deteriate such that they will not be able to ride through severe voltage or frequency excursions. For example, Luminant has done testing of 480v contactors that when purchased new exhibit a drop out voltage level but over time, the drop out level will deteriate to a level. Since there is no method for determining when to replace equipment susceptible to voltage ride through criteria, this requirement is not auditable for the maintain requirement. The “maintain” requirement should be removed. The cost of meeting this requirement could potentially discourage new generation. Overall, requirement R5 provides little benefit to the reliability of the BES, and Luminant recommends that this requirement be removed.
1. Requirement R1 and R2 discuss generator frequency and voltage relaying to be set such that they do not trip within the “no trip zone” of Attachement 1 and 2 respectively. Luminant believes that these requirements should only apply to relays that use frequency or voltage sensing only. Impedance, and voltage controlled over-current relays should not be included since they are part of the Generator Loadability and AVR Control standards. Relays using both voltage and frequency should not be part of the standard. Alternately, if volts per hertz relays are included, Luminant recommends that an additional requirement R2.2 be added to take in consideration volts per hertz relays. R2.2 would become “Generator volts per hertz relaying shall not cause a unit trip for conditions that are less than 116% of generator rated design voltage and frequency and last for less than 1.5 seconds.” For footnote 1, individual curves would have to be listed for each protective relay function, as the Attachement 1 curve is for voltage relays only. 2. R3 is an administrative requirement that provides little or no benefit to the BES. Luminant recommends that the requirement be removed, and Requirements R1 and R2 should be modified to delete the reference to R3 as follows; “ … unless the generator owner has identified an equipment limitation …” 3. R6 should be at a minimum of 90 days due to some entities have a large number of generating units. 4. Overall, this standard should address voltage and frequency relay settings only.
Individual
Greg Rowland
Duke Energy

Yes
Yes
No
Footnote 4 – strike the phrase “or plant” in both places, since this only applies to a unit. Also add the phrase “and by demonstrating a reliability need” to the end of Footenote 4. Otherwise, this standard could be made applicable to a small unit that has no impact on reliability.
No
Need to specify “net” or “gross” capacity factor for the calculation.
• R2, 2.1.3 – Please revise to specify total inertia. Total unit inertia should be given to include all coupled rotating elements. The way this is currently worded, it could lead generators to only provide the generator H values. • R2, 2.2 – Insert the phrase “or individual unit” after the word “aggregate”. • Page 15, Equivalent applicable unit - Identically designed generation units are identical in control response, independent of site location. New techniques for validation eliminate the impact of the grid on the validation efforts. Thus, credit for sister unit validations should be available independent of the location of a unit or connected voltage.
No
Generator Owners don’t currently have the capability to provide this information, and will need time to obtain the capability and perform the studies. Requirement R4 should be removed from Effective Date sections 5.1, 5.2 and 5.3 because one, two or three years is insufficient time. R4 should have its own effective date section specifying an effective date of the first day of the first calendar quarter five years following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter five years following Board of Trustees adoption. Requirement R4 should also be revised to allow the Generator Owner 180 days (instead of 60 days) to respond to a request and provide an estimate of a unit’s performance during frequency/voltage excursions.
No
The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)”as follows: a. Normal Conditions: ±5% Continuous Duration b. Emergency Conditions: ±10% not specified Duration These Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second is to utilize expensive voltage regulation devices, normally not utilized at power generation plants. This standard shouldn’t dictate a solution to the situation where a generator goes offline due to low voltage on the transmission system, because in many cases the generator going offline may not be a problem for the overall transmission system. In situations where it is a problem, a collaborative effort between the Transmission Planner and the Generator Owner would be the best approach (see AREVA white paper that has been provided to the SDT). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
The frequency and voltage ride-through curves are at the point of interconnection. Conditions inside a generating plant will depend upon how the generator responds to the transient. Models will have to be

built and validated against plant-specific auxiliary equipment performance expectations.
Group
MRO NSRF
WILL SMITH
Yes
Yes
No
It is suggested the following modification to R5 will more clearly mirror the SDT intent as depicted in the question: "…any unit/plant meeting the Registry Criteria not included in the Applicability that includes one of the following…"
Yes
Please give consideration to the following suggestions from the MRO NSRF: 1. In Requirements, R1, bullet 2 – change the wording to be more similar to bullet 1, "obtain model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations". Software manaufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. As in the more general wording bullet 1, requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets depending on the Generator Owner licenses or lack of licenses. 2. In Event Triggering Verification Table, Item 6, Cell 1 – fix typographical error of ". . . system event did not did not match . . ." 3. Please restructure requirements and evidence to allow for posted instructions and model data to meet compliance for appropriate requirements such as R1,R2, etc… 4. In the second bullet item under Applicability Section 4.2.1.2, recommend the drafting team remove the word "consisting" and add the word "solely" to avoid confusion. Section 4.2.1.2 would instead read "Each generating plant / Facility comprised consisting solely of …". 5. Recommend the capacity factor test in Applicability Section 4.2 be revised to state: "Applicable units or plants with an average capacity factor greater than 5 percent …" As currently drafted, it is unclear as to whether all units, applicable or not, are included in the calculation of the Capacity Factor (CF). In cases where an entity has a plant with one 60 MVA unit and three 15 MVA units, the units less than 20 MVA would not be applicable per the criteria in MOD-026-1. However, would all units still be factored into the CF calculation? 6. Requirement R6.3 specifies "a disturbance simulation results in …. exhibiting positive damping". Guidance is needed as to what is considered acceptable positive damping. 7. R6 has two periods at the end of the paragraph just before [Violation Risk Factor …] 8. In the applicability section 4.2, the undefined term bulk power system is used. To avoid confusion regarding the applicability, it is recommended the defined term Bulk Electric System be used.
No
Since most existing facilities are likely not designed to a frequency or voltage ride-through standard, the estimate may be very difficult for owners to provide. Staged testing would not be practical for making this determination and engineering analysis may not have the accuracy to make it useful for use by Transmission Planners.
No
A Standard cannot tell us what or how a generator needs to be built. Section 215 of the Federal Powers Act "(i) Savings Provisions, (2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services". We believe that R5 is directing "GO's to design, build and maintain new unit…" and is in violation to the Federal Power Act as stated above. As R5 is written, if an entity builds a new unit and it trips for a voltage or excursion event within the parameters of Attachment 1 and 2, the entity is non compliant. This Requirement seems to be based on future technology that does not exist today. The SDT should state that the parameters of Attachment 1 and 2 "should" prevent a unit from tripping. R5 is written as an absolute and may reduce a new unit from being built. With the risk of non compliance being $1 million per day, it is easier and less risky not to even build a new unit.

The MRO NSRF believes that an entity having to attest to the fact that a generating unit or plant did not trip offers no foreseeable benefit to reliability. As currently stated, Measure M5 could be interpreted to mean that an entity would need to provide a letter of attestation each day or month a generating unit or plant were to function as intended. The MRO NSRF recommends the drafting team either remove this statement or else rephrase the Measure to avoid the expectation that entities verify normal operation. Additionally, as frequency excursion and voltage excursion are not NERC-defined terms nor terms to be defined as part of this project, recommend the terms be placed in lowercase letters to maintain consistency with the Requirement. M5. Each Generator Owner shall have evidence, such as dated unit output records, trip investigation reports or disturbance monitoring records, showing that each unit trip did not result from a FfrequencyEexcursion or VvoltageEexcursion as specified in Requirement R5, or evidence that a listed exception applied, or provide an attestation that the generating unit or generating plant did not trip. Please give consideration to the following suggestions: 1. In Requirements R2 – the text refers to “non-protection system equipment” but this terminology is not defined. Provide some definition/description and perhaps a list of this type of equipment in a footnote to improve clarity. 2. In Requirements, R3 – add the requirement that the GO provides the expected duration of the limitation, if it is known. 3. Request MOD-026 and MOD-027 be verified for redundancy with PRC-024. In the applicability section the only reference is to Generator Owner. It is recommended the applicability section include a statement that the affected units are only those that are a part of the Bulk Electric System.
Individual
Richard Vine
California Independent System Operator
The California Independent System Operator Corporation has adopted tariff requirements for generator frequency and voltage ride through capabilities that apply to synchronous generators as well as requirements for generator frequency and voltage ride through capabilities that apply to asynchronous generators. As written, the requirements of draft PRC-024-1 apply to both synchronous and asynchronous generators. The ISO requests that the Generator Verification Standard Drafting Team confirm this reading of draft PRC-024-1, and suggests making this clarification in PRC-024-1 as well.
Group
Arizona Public Service Company
Janet Smith, Supervisor Regulatory Compliance
Yes
Yes
Yes
The SDT has done a great job. The requirement is simple, clearer and supports reliability.
Yes
No
This type of data is not going to result into any more accurate simulation than the existing methodology which does not include this data. There are many other inaccuracies involved in modeling and scenario planning for islanding studies. It is a misconception that just by having more complex modeling will improve accuracy and thus reliability.

No
Yes, the requirement is technically achievable. However there is a problem with measure and how compliance may enforce it. Generating units trip for many other reasons other than frequency and voltage excursions. The meaure, as written, will require a GO to prove that the unit(s) did not trip due to frequency or voltage excursion which may be impossible to prove. Even if it finds other reasons, it may be hard to prove that frequency and voltage excursion did not contribute to that other reason. Thus, a GO may be non-compliant unless for each unit trip it can clearly prove that the frequency and voltage excursion did not contribute to trip, which may be impossible to prove.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
Yes
Yes
Individual
Daniel J Hansen
GenOn Energy
Yes
Yes
In Attachment 1, the title “Consideration for Early Compliance” should be changed to “Comliance for Prior Verification”
Yes
Yes
Yes
Yes
Conditionally yes; unconditionally no. It is achievable for any plant with a modern AVR and unit connected auxiliaries. Problems arises for unique circumstances that may require auxiliaries that are not unit connected (directly connected to transmission systems). Existing plants orginally designed with unit connected auxiliaries have been forced to extend auxilary power feeds directly from transmission level voltages. It is believed that transmission system performance better than Attachment 2 is available at the majority of locations, and therefore, it is not necessarily appropriate to make this the design criteria for every future generating station.
Thank you to the SDT for you efforts to produce a quality standards. R3 should be worded in a similar manner to R4. “The Generator Owner shall document the estimated equipment limitations…” The problem with a requirement like R3, is that documenting “each” equipment limitation on older

facilities will contain uncertainties and unknowns. The implementation schedule for the requirements will be more efficient if the schedule is aligned with the PRC-019 schedule rather than having the two similar efforts on different tracks.
Individual
Patrick Brown
Essential Power, LLC
Yes
Yes
Yes
Yes
Yes
Yes
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
No
If the GVSDT intends to incorporate definitions or calculations from Appendix F of the GADS Data Reporting Instructions, the relevant information needs to be expressly incorporated, perhaps in an additional attachment to the standard. Requirements that refer to outside materials are not helpful and should be avoided (notwithstanding the desire to avoid a future need to modify the standard to the extent that Appendix F is amended from time to time in the future).
Yes. See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.2.1 of the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence reads as follows: "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected to the point of interconnection at greater than or equal to 100 kV." 2. PacifiCorp believes that the second bullet under Section 4.2.2.2 of the "Applicability" section introduces confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing bullets: • "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and • Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating plants/Facilities with total generation greater than the thresholds established in the Applicability

section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.6."
Yes
No
While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
While PacifiCorp has no concerns with this Requirement R5 as applied to new units or generating plant/facilities meeting the point of interconnection frequency excursion performance depicted in Attachment 1 (for the corrected WECC curve), PacifiCorp believes that new units or generating plant/facilities should meet the voltage excursions performance depicted in Attachment 2; however, ultimately it will be up to generator manufacturers to implement necessary facility changes to withstand the voltage excursions.
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Kirit Shah
Ameren
Yes
No
The comments and guidance of the GVSDT are greatly appreciated. However, we have a concern/question, how would the periodic verification/testing requirements for MOD-026 would align with other such requirements in place for MOD-024, MOD-025 and with reporting requirements of MOD-012 and MOD-013? We would like the GVSDT to consider a well-coordinated periodic verification and reporting needs for all such requirements to provide the GO flexibility to schedule their tasks to meet these requirements without undue burden to take facility out of service at different times.
No
We believe and recommend that this should be the responsibility of the Transmission Planner rather than the Planning Coordinator. At a minimum the language should state “Planning Coordinator and Transmission Planner”.

Yes
(1) The requirements 4.2.1.1 and 4.2.1.2 refer to bulk power system (BPS). We suggest that GVSDT includes definition of BPS in the standard. (2) We suggest that GVSDT clearly specify that "point of interconnection" referred to in R2.1.1 to be the same as defined in PRC-024-1. (3) In Attachment 1, Row 4 it seems to imply to us that some use of "Sister Units" is allowed to meet the requirement. . We suggest that the GVSDT clarify and include this option in the body of the Standard (preferably) or in Attachment 1 as an option? (4) Requirement R2.2 states that an Applicable plant with gross nameplate ratings of the units < 20 MVA should use a plant aggregate model. Can the GVSDT clarify the type of model and provide example for each? (5) There are 17 technical papers referenced in Section G of the Standard. Would the GVSDT make them available on the NERC website? (6) For Requirement R3, we did not find anything in the standard that specifies how closely a model response must match the tested response of a generator. We believe that unless this is clearly specified, it could lead to disagreements between the Generator Owner and Transmission Planner over what constitutes a verified model.
No
At the end of R4.2, we suggest to add “the Transmission Planner’s voltage recovery characteristic from R2 part 2.1.1” since that may well have bearing on the estimate. We understand the reasons for such studies, but we ask the GVSDT to consider the fact that more than 60 days may be needed to estimate generating unit performance especially the first time it is done for each unit. As long as this applies only to generator frequency and voltage protective relaying (and not to station auxiliaries) developing these estimates in the time frame mentioned earlier is achievable.
No
(1) We understand this to include generating plant auxiliary load based on the GVSDT reply to our draft 2 comments. If still is the case, please clarify and explicitly insert “including its auxiliary systems” after generating plant so that all GO understand it. (2) Many 480V class contactors drop out in the 70% to 80% voltage range, so we doubt they’ll ride through the 2 to 3 second portion of the voltage excursion. The middle portion of your voltage excursion curve is more stringent than the CBEMA and SEMI curves, both of which recover to 80% in 0.5 sec. Transmission system protection in our system will clear faults faster than the proposed voltage excursion curve, thus in effect yielding a voltage recovery curve with shorter durations for the voltages specified. We would ask the GVSDT to consider what we feel is a more realistic approach of designing a new generating facility to the Transmission Planner’s voltage recovery characteristic allowed for in R2 part 2.1.1 is achievable now. What was the basis on which the proposed voltage excursion curve developed?
(1)Under Applicability it should state that ‘all existing generators meeting registry criteria’ and also ‘new generating units that will meet the registry criteria.’(2)Please modify the Effective Date and Implementation Plan to provide a five year phase-in to match that of the companion PRC-019-1. Generator voltage protective relaying must be reviewed in both these standards, and we believe that doing so on the same schedule will yield a better coordinated result and less confusion. Each of these standards will consume valuable resource time and the efficiency of reviewing each generator concurrently will improve BES reliability. (3)Please add ‘R1, 1.3 If clearing a system fault necessitates disconnecting a generator, then this action is acceptable within the “no trip zone”.’ This affords the same practical reality recognized for voltage excursions.(4)Please be clearer regarding the Voltage Ride-Through curve. Attachment 2 Voltage Ride-Through Curve Clarification #2 could be interpreted to imply that the curve is based on three phase faults. But the inclusion of #5 states that phase-to-ground or phase-to-phase voltages (minimum or maximum as appropriate) are assumed. Of course, for a three phase fault the each phase’s voltage is equal. So we interpret #5 to mean that the actual fault type to be simulated should match the Transmission Planning criteria, which for example may be double or single line to ground faults with delayed clearing. We recommend to the GVSDT to align this with the TPL standards, which use three phase fault or single line to ground fault with Normal Clearing, but only single line to ground fault with Delayed Clearing. We would appreciate an example or in depth explanation to tie these together. Please annotate Attachment 2 with references to R2 and clarifications on page 18. (5)Delete ‘or generating plant’ from R1, R2, and R3 to be clear that the generating plant auxiliary loads are not subject to these requirements. Alternatively, restate R3 as “...that prevents a generator frequency or voltage protective relay generating unit or generating plant, from meeting the criteria in Requirements R1 or R2 including study results, experience from an actual event, or manufacturer’s advisory” to be consistent with R1 and R2. (6)At the end of Requirement

R4.2, please add “the Transmission Planner’s voltage recovery characteristic from R2 part 2.1.1” since that may well have bearing on the estimate. (7)From our perspective, Requirement R5 doesn’t make sense for a newly designed generator. We would suggest the GVSDT to realign M5 to be prospective and to require the GO to provide design basis evidence appropriate for the stage of design of new generators. In early conception stages, the GO would request the Transmission Planner’s frequency and voltage excursions. Then the GO would design the generator train and auxiliary system to ride through, and if infeasible, request technical exceptions. Late in the design process the generator frequency and voltage protective trip settings would be determined; it would be appropriate at that time to provide them R6 requests for future system studies. (8)For Requirement R6 we oppose providing this specific information to all these functional entities, given that they are getting the R4 estimate of performance during such excursions. (9)If R6 is retained, please make the following changes: (a) We strongly prefer a reporting of exceptions to the standards frequency and voltage excursion ride-through curves rather than reporting all these relay settings. Use PRC-006-1 Attachment 1 page 28 of that standard for frequency reporting. Develop a similar envelope for voltage reporting. If a Transmission Planner’s voltage recovery characteristic allowed for in R2 part 2.1.1 differs that should be provided for the generators in their area. Generator Owners would then report exceptions. (b)Insert “frequency and voltage” between generator and protection in the first line.(c)Delete “and within 30 calendar days of any change to those trip settings,” because this creates an open ended obligation on the GO. (10)We would suggest the GVSDT to not capitalize frequency and voltage excursions as they are no longer defined terms. (11)We suggest the GVSDT to replace the time-based or binary VSL for R1, R2, R3, R4 and R6 with a VSL in terms of the GO % of MWh produced for the time period of violation. This better characterizes the risk to BES reliability. We propose <5% for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe. As presently proposed a generator with no operating hours could cause a GO to incur a Severe violation though it posed no risk to the BES. (12)From our perspective, the VSL for R5 doesn’t make sense for a newly designed generator. We suggest, a time-based VSL with x days late in providing R4 or R6 type information. . In this regard, we propose to the GVSDT 30 days late for Lower, 31 to 60 days late for Moderate, 61 to 90 days late for High, and >90 days for Severe. (13)PRC-024-1, R2.1 states that generator terminal voltage refers to Attachment 2. However, in R2 itself, footnote 3 states that voltage excursion applies to point of interconnection, meaning the GSU high-side. We suggest the SDT resolve this discrepancy. (14)Attachment 2 should include footnote similar to footnote 3 provided for R2.
Individual
Larry Raczkowski
FirstEnergy Corp
Yes
Yes
Yes
Yes
FirstEnergy would like to make the following comments on this standard: 1)Under the Applicability section 4.2.1.2, the use if the term "common bus" should be clarified as either the low-side or high-side of the GSU. 2)Footnote 1a on Page 2, says that “… the generator excitation control system includes the generator, exciter, voltage regulator and power system stabilizer.” While we understand that the excitation system supplies the generator field, there is a separate Model for the Generator (typically GENROU). We suggest omitting the word generator from the footnote to avoid confusion. 3)Suggest rewording 2.1 to begin with, “Provide models acceptable to the Transmission Planner, including verified parameters …”, rather than “Perform verifications …”. The GO provides information on applicable models as well as the parameters. The TP actually runs the models to determine system impact. 4)Requirement 2.1.1 requires “Documentation demonstrating the applicable unit’s model response matches the recorded response for a voltage excursion at the applicable unit’s point of interconnections from either a staged test or a measured system disturbance. •Please define or qualify the term “matches”. This is a subjective term, subject to interpretation of results; i.e., what %

error is considered “matching”. •Refers to recorded response “… at the applicable unit’s point of interconnection …”. This should be reworded to “at generator terminals”. An excitation system controls to the generator terminals since this is where Voltage and Current inputs to the AVR originate. Further, this is where measurements are taken during dynamic testing. •"a measured system disturbance” is not practical for a GO, and should be eliminated. DME is owned by the TO, and do not have access to results of disturbances.
Yes
Yes
Individual
Mark B Thompson
Alberta Electric System Operator
The AESO does not support the changes made to the Curve Details, in the Voltage Ride-Through Curve Clarifications section of the standard, in particular the use of the term “base voltage” . In many parts of the Alberta transmission system the maximum normal operating voltages are significantly higher than 1.05pu of than the “base voltage” used in studies. The system has been studied, planned and designed around these higher voltages. For example; in a study the base (nominal) voltage is chosen to be one per unit (1.0 pu) equals 240 kV but in the study area typical operating voltages are 256 kV (1.07 pu) and can be as high as 1.10 pu.
Group
PPL Electric Utilities and PPL Supply NERC Registered Organizations
Annette M. Bannon
Yes
Yes
No
The term “standby” in footnote 2 on p.2 bears definition. Is 5% capacity factor the criterion to be used in establishing standby status? If so, it would be best to make this standard entirely unit-based, eliminating all references to plants.
Yes
a. Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of running dynamic models or representing within the model the system we connect-to. R2.1 1 should require the TP, not GOs, to run models and develop the referenced documentation (or, if the result is not suitable, open a dialogue per R3). The same comment applies for R2.2. b. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. 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. It was stated in the 7/29/11 webinar that a signal-to-noise ratio of at least 5:1 is needed for a meaningful validation, but this criterion is not included in the draft standard. c. We suggest replacing “rotational inertia” in R2.1.3 with “inertia constant (H),” the rotational inertia divided by MVA rating, since this is the parameter of interest for stability studies. d. The 4/6/10-year periods specified in paras. 5.1.1-5.1.4 and 5.2.1-5.2.4 on pp. 3-4 of MOD-026-1 should provide for existing plants enough time to catch a disturbance of sufficient magnitude for verification purposes; but the one-year allowance in row 3 on p.15 for plants that are new or have replaced controls equipment may prove inadequate, especially since (per comment 5b above) we don’t currently know what sort of transient is needed. At least a four-year window should be granted for the initial verification. It is also unclear how one decides up-front the applicability of this standard to a new facility. The past-years test of para. 4.2 cannot be used; and a unit anticipated to have less than a 5% capacity factor may prove otherwise depending on market conditions or other factors. In any event the one-year verification limit for new and modified units is inadequate if it takes longer than this amount of time just to determine whether or not MOD-026-1 is applicable. e. The use of the undefined term “technically justified request” in R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? Further, the 90 day time period should not begin until both parties fully understand the “technically justified request.” f. The means by which a walk-down would lead to identification of model parameters in the second bull-dot of R.5.2 is not understood.
No
Independent generators provide model data to the TP/TOP and TO, who then run their models, but we do not ourselves have means of predicting responses to voltage and frequency excursions. This is especially the case when one must, per R4.1, engage in the phenomenal complexity of calculating the transient performance of auxiliary buses and identifying the short-term drop-out thresholds of the multitudinous pieces of equipment they power. The references in R4.1 and 4.2 to experience, actual event histories or sound engineering judgment as alternatives to a computer model are not helpful, because meaningful assessments can be made only if one has relevant data (i.e. high-speed records of past disturbances, at HV, MV and LV voltage levels) and issue a PV. Further on the subject of complexity, there are a variety of aux bus configurations possible for our multiple-unit plants, any one of which could be deemed normal depending on circumstances. Having to check every aux bus configuration for every units-running combination would be unduly burdensome, even if it were possible. The fact that R4 cites “Frequency/Voltage Excursions” (apparently meaning simultaneous deviations of these parameters), while R5 is careful to refer to “frequency excursion or voltage excursion,” adds confusion. Another concern is that the boundary conditions for the above-described analysis are presently undefined, with the standard invoking instead a “dynamic simulation provided by the Transmission Planner.” For the reasons stated above, the proposed requirement R.4 should be eliminated.
No
It is possible for new facilities to buy steam turbines that permit operation in accordance with Att.1. We cannot confirm that it is possible to do so for all fossil unit sizes or generation unit types, however, and recommend that question 7 above be put to OEMs. This is particularly the case for gas turbine engines, for which the limiting factor may be surge avoidance rather than resonance margins. Note also that such units may auto-unload at abnormal frequencies. This action may not provide the grid ride-out capability wanted, despite satisfying R5’s no-trip requirement. The general acceptability stated above for steam turbines bears clarification, however, because OEM guidelines for off-frequency operation typically have a lifetime basis. That is, each transient results in cumulative fatigue damage. The frequency curves of PRC-024-1 are consequently not acceptable for an unstable grid that often swings to the max-specified deviations, and a statement should be added to this standard to the effect that the no-trip zones of Att. 1 apply for frequency excursions to the extremes no more frequently than once per decade. Att. 2 presents a problem in that the deviation location is specified to be the point of interconnection, but GOs are being asked to confirm that all MV and LV devices required to maintain the unit on-line will not drop-out. An excursion to -10% voltage on the 230 kV span would correspond to -10% on the LV and MV systems only for theoretically ideal transformers, and the actual transient at critical loads may be greater. It would not be possible in any event to get OEMs to guarantee that the auxiliary equipment they supply will not drop-out for the Att. 2 excursions of 10 minutes at -10% voltage, 2 sec at -35% or 0.2 sec at -55%. The industry standard on this subject is ANSI C84.1, which stipulates voltage boundaries of +/- 5% for continuous operation

and +/- 10% for emergency operation of no specified duration. If NERC feels that the criteria of Att. 2 are important for BES reliability they should start by asking the appropriate ANSI and IEEE committees to revise their standards accordingly. We cannot support PRC-024-1 until its criteria become the nationally-accepted norm, because we otherwise would be making a commitment that it is impossible to fulfill.
a. A standard-specific definition of the word “plant” is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit’s behavior. b. Clarity is needed for the expression, “it does not trip,” in R1 and R2. Does this mean that the protective relaying does not trip, or that the unit does not trip? In the latter case do the requirements pertain only to interlocks, or do they also cover disturbances that may result in a trip? Such differentiations were clearly spelled-out in the PRC-005-2 draft currently out for voting, and they are needed here also. What seems at first to be relay-setting requirements may in fact also incorporate aux equipment drop-out, invoking for existing equipment the concerns stated above in response to question 7 (with regard to designing a standard based on a technology for which vendors may not guaranty performance).
Individual
Jeanie Doty
Austin Energy
Yes
No
Per R1. the TP should provide periodicity.
Yes
The standard is not applicable to the Planning Coordinator. Does the SDT mean TP?
No
The NERC Glossary is the correct reference for definitions used in the Standards. Referencing GADS is not appropriate.
The standard drafting team may consider adding the sentences in footnotes 2 & 3 directly to section 4.2 Facilities to avoid potentially unecessary complexity. Also in section 4.2 Facilities, the term bulk power system (BPS), not BES is used. Would use of BES instead of BPS remove the need for footnote 2 without changing the overall intent of the SDT?
Yes
Individual
Randall McCamish
City of Vero Beach
The applicability refers to the “bulk power system”, e.g., “4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating) directly connected to the bulk power system”. The term “bulk-power system” should not be used in the standards as it is ambiguous and should be replaced with “Bulk Electric System” We do not understand how the Applicability of 4.2.1.2 means. We suggest making the language clearer. R2.1.1 should only apply if a system disturbance actually happens and should not require a staged test. A staged test could threaten the reliability of the BES more than inaccuracy of an excitation system model. R4 should specifically exclude temporary changes, e.g., generator AVR settings are often changed when the unit is started or shut-down, if the AVR is planned out of service, etc., we believe the intent of the standard is only to communicate more permanent changes and not temporary changes. R5 is ambiguous. What is technically justified? Who gets to decide what is technically qualfied?

R3.1, the second bullet, should be clarified to explain that the equipment replaced is plural, meaning all equipment causing a limitation would need to be replaced, e.g., if one piece of equipment was replaced, but another stil causes a limitation, the “grandfathering” of existing equipment lmimtations should still be in place. R1 and R2 are inconsistent with R5, bullet 5.2. R1 and R2 provide no exceptions for a new plant/wind farm/solar farm, R5 bullet 5.2 does. R6 is ambiguous as to whether or not any time any protection settings are changed, whether or not they violate the curves, the entity has to notify and provide the settings. It should be limited to only generators that violate the curves. Or is it that all trip settings of all generators are intended to be modeled? We would think that we do not need to model the generator trip settings for those that meet the curves because the UFLS program is supposed to prevent us from reaching those curves. Hence, we should only need to model the trip settings of those generators that do not meet the curves.
Individual
Christine Hasha
ERCOT
Comment 1: Requirement R2 and voltage ride through curve in the PRC-024 Attachment 2 are applicable to the voltage at point of interconnection to the Bulk Electric System (BES). However, in requirement R2.1 “When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:” The clarification is needed for R2.1 that describes how the generator terminal voltage will affect the applicability to this requirement. Comment 2: In the attachment 1 and attachment 2, it is not clear if a unit can be allowed to trip instantaneously under extreme high voltage or high/low frequency occurred during and post disturbance period. For example, the physical limitation requires a wind farm to trip the turbine instantaneously when voltage is above 1.25 pu. If there is a short duration of overvoltage, 1.3pu for 0.15 second, during and post disturbance period that cause the wind farm trip the turbines, does this wind farm violate the requirement as stated in attachment 2 that requires the wind farm to remain in service for 0.2 second when voltage is above 1.2 pu?
Comment 1: In the Applicability section, it is not clear in 4.2.3.2 which units/plants are required to meet this standard. For example, a generating plant that is greater than 75 MVA and consisted of 75 1MW generating units, is this generating plant required to meet MOD-026-1? Another example, a generating plant that is greater than 75 MVA and consisted of one 45MVA generating unit and two 15MVA generating unit, is only the 45MVA generating unit required to meet MOD-026-1?
Individual
Ed Davis
Entergy Services
MOD-026-1 R2.1.1 is: 2.1.1. Documentation demonstrating the applicable unit’s model response matches the recorded response for a voltage excursion at the applicable unit’s POINT OF INTERCONNECTION from either a staged test or a measured system disturbance. We recommend the POINT OF INTERCONNECTION be changed to GENERATOR TERMINALS.

Individual
Patrick Farrell
Southern California Edison Company
Yes
Yes
Yes
Yes
While an active closed-loop voltage regulation function is useful in distinguishing transient voltage and frequency responses within mere cycles or seconds of perturbations, a similar requirement should be added to MOD-026-1 to require variable generators who were exempted from the standard by the condition added to Attachment 1 to provide similar plant voltage/var control, design, and test data to the Transmission Planner. The automatic switching of capacitor banks and reactor banks can play a role in maintaining the voltage stability of the system.
Yes
No
The language in the requirement is acceptable, but the frequency curve identified for generators is too restrictive for hydro facilities, which are often dispatched to provide VAR and voltage support. SCE's hydro generation plants operate at very low RPM, which provides them with the ability to operate safely above (60-78 Hz) and below (<58 Hz) the frequency curves in Attachment 1 and Attachment 2, respectively. As a transmission operator, SCE applies this flexibility in its hydro generation plants to compensate for system instabilities resulting from VAR and voltage excursions. In addition, SCE's employs its hydro plants to support system restoration.
The standard should allow for wider regional variances - for example, WECC allows lower frequency and voltage excursions.
Group
Western Electricity Coordinating Council
Steve Rueckert
Yes
The introduction to this comment form indicates that "The typographical errors in R2.1.1 language has been corrected to clearly state expectation that, “The unit or plant’s model response matches the recorded response for a voltage excursion at the generator or plant point of Interconnection..." However, the versions posted for review (clean and redline) do not indicate that the "unit or plan's model..." They say the "applicable unit's model response matches..." There is no reference to plants in part 2.1.1
I am unsure of the intent of the phrase "estimate of the performance of the units during frequency and voltage excursions." Is this intended to mean that the owners should estimate whether or not the unit will stay connected, or provide some estimate of the unit's dynamic performance and response to an event? I also don't understand the purpose of this requirement. If models already exist and are available to the Transmission Planners, then the owners should be validating the model. As part of the validatio process the owners should be able to tell the Transmission Planner what the performance will be. Is this for units for which models have not been validated?

The Attachment depicting the No Trip Zone for frequency excursions for the WECC Interconnection is incorrect. It is missing one of the steps from the materials provided to the drafting team in July. The table is also missing a step. This must be corrected. In my opinion, the table identifying the High and Low Frequency Duration information is hard to interpret. As depicted, the table appears to be giving a range of time that a generator must stay interconnected at a specific frequency. I am not familiar with the requirements in other regions, but in WECC, we have specified a specific time that a generator must stay interconnected for a frequency range. In looking at the WECC table included int he draft standard I would not be able to discern how long a generator had to stay interconnected if the frequency were at 59.0 Hz. Similarly, I have the same problem with the information in the tables for the other interconnections. After discussions with drafting team representatives, an suggested revision for the format of the tables has been proveded to the drafting team for consideration. Even with the inclusion of the (not including the lines) statement on the No Trip Zone plot, it is still difficult to determine minute specifications from the plot. Depending on the quality of the diagram and the thickness of the line, there will still be the potential for debate. I believe a solution is to indicate the plot is for illusrative purposes only, and the specifics are provided in the tables. With the suggested format changes provided to the drafting team, there should be no room for speculation. Whether the Off-Nominal Frequency Capability Curve is used for illustrative purposes as suggested above, or for specifying details, it is difficult to view as presented. One option would be to provide three individual plots, one for each interconnection, and include them all as Attachment 2. This way you could still refer to Attachment A in Requirement R2, and perhaps add language such as "appropriate plot in Attachment 2" to the requirement.
Individual
Ken Wofford
Georgia Transmission Corporation
Yes
Yes
Yes
Requirement 5 seems to imply that GO’s must provide a written response regarding units below the Registry Criteria unit MVA thresholds (< 20MVA) if a Planning Coordinator provides a technically justified request to perform a model review. Can the SDT confirm this intent? Additionally, there could be some confusion with the language as written to imply the PC’s “technical justification” includes the bulleted items of R5. GTC is assuming the SDT’s intent is for the “GO’s written response” to include the bulleted items and therefore requests additional clarity. GTC recommends the following: Each Generator Owner shall provide a written response to its Planning Coordinator, within 90 calendar days following receipt of a technically justified request from the Planning Coordinator to perform a model review of any unit/plant not included in the Applicability. The written response shall include one of the following [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]: • Details of plans to verify/correct the model documentation and data as needed (in accordance with Requirement R2) • Corrected model documentation and data including the source of revised model data.
No
We ought to be able to verify FIDVR mitigating machines below 5% capacity factor.
Yes
Don't know
Comment on R6, Severe VSL. Time limit is within 60 calendar days, however the time limit for R3, R4 and R5 state 61 calendar days. Wording for Severe VSL for R3, R4, R5 and R6 should have the same time limitations of either “…within 61 calendar days” or revised so that the documentation was “communicated greater than 60 calendar days….”.
Group
Southern Company
Antonio Grayson

Yes
Yes we agree with this concept. It is not practical, and there is no benefit to reliability, to require validation for units which do not include an active closed-loop voltage regulator function.
Yes
A periodicity of ten years between model verifications when there are no special circumstances is appropriate. What is the basis for a ten year re-verification for units where no changes to the excitation system have occurred? A ten year verification basis for an non-modified digital excitation system does not seem to be justified.
Yes
Allowing a Planning Coordinator to request additional model information only if technical justification demonstrates a mis-match between the measured unit response and the model's predictied response is appropriate. Even if the unit was a contributor to a stability limit, additional model information is really only needed if the model did not sufficiently emulate actual equipment response.
Yes
We agree that the collection of preliminary excitation control system model data from the equipment manufacturer is outside the scope of this standard. Also, any pre-COD staged testing to collect equipment responses to be used to verify the model can be required via Interconnection Agreements. It is understood that any equipment responses collected through pre-COD staged testing with final equipment settings in place that is subsequently used for model verification per the Requirements in the standard would result in fulfilling the requirements for model verficiation for the next 10 years per the Periodicity Table or until a special circumstance occurs leading to an earlier model re-verification as detailed in Requirements R3, R4, R5, or R5. The limitation to allow sisterhood for only those units at the same physical location should be extended to all identical units for the same GO/GOP - a sister is a sister is a sister. The GO should be allowed to take credit if he can show that the physical location is not a factor in the comparison. In section 4.2.1.1, and other places, we don't understand the use of "bulk power system" –shouldn't this be "Bulk Electric System". In 4.2.1.2, second bullet, eliminate the word "comprised" as it is redundant with "consisting". The same redundant use of "comprised" is insection 4.2.2.2 and 4.2.3.2, second bullet. In R2.1.4, the intended information is not clear – the closed loop voltage regulator part is not needed – it is part of the previous wording. In R2.2, replace "For plants" with "For applicable plants". Please add "where applicable" each time the "plant volt/var control" is used. Due to R5, the Planning Coordinator should be listed in the 4.1 Functional Entitles. R5 is confusing – the bullet items list what the GO response should include, but the sentence is written such that the list is what the model review must include. In R2.1.1, please insert "or voltage at the generator terminal" to "at unit's point of interconnection".
No
We cannot agree with the approach of Requirement R4 due to the uncertainty about how to estimate the performance of "each" plant system, sub-system, or component that could cause the unit to trip for the voltage excursion profile of Attachment 2. For most units, this estimate may vary from a few cycles (examples: dropout of low voltage motor contactors or an auxiliary control relay) to up to 1-2 seconds (examples: tripping of boiler controls or medium voltage motors). Determination of a more accurate time estimate would require detailed dynamic analysis, which would entail significant engineering study and involve assumptions and judgment based on experience. Data from actual event histories, if available, would likely not match all points of the Attachment 2 time-voltage profile. The voltage excursion profile needed for an evaluation would be the voltages present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. Without detailed analysis, only a rough estimate could be made which would probably be of limited value for transmission system analyses. A conservative approach would be the "go/no-go" approach and identify those units that are likely to trip for a specified voltage excursion. For the current requirements stated in R4, the 60 day time requirement would be a significant challenge for a GO to meet for a single unit. For GOs who have a large number of units and limited engineering resources, the 3-year phase-in period will be impractical to establish on many units the estimated performance of "each" plant system, sub-system, and component that could trip. Bottom line is, the concept may seem simple enough in principle, but these requirements cannot be practically met. We believe the scope of the standard should be limited to identification of the protection function trips per R1, R2, R3, and R6 only.

No
We recommend R5 be eliminated. New plants should be subjected to the same requirements as existing plants. The design of plant systems, sub-systems, and components are based on industry technical standards (ANSI, IEEE, ASME, etc.). Establishment of new NERC plant performance requirements must be coordinated with the industry through those standard processes. We believe significant R&D will be required to achieve significant new plant design requirements that can be used to revise the industry technical standards and that plant, system, and equipment designers and builders can meet. The scope of systems and components that must be addressed includes, but is not limited to, turbine generators, transformers, feed pump systems/controls, boiler control systems, reactor protection systems, emergency diesel generators, AC motors, pumps, fans, AC motor contactors, auxiliary relays, etc. In addition, significant costs will be incurred by the industry that we believe demand further justification.
Yes: 1) We respectfully disagree with the SDT's response to our prior comment related to maintaining the safety of the reactor core at nuclear plants for voltage or frequency transients. The intent of our comments is to ensure that application of this standard to nuclear units is coordinated per the requirements of NUC-001. Employing any changes to the grid frequency and voltage ride-through requirements may impact the licensing and design basis of nuclear facilities. NUC-001-1 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown. This is achieved through development of Nuclear Plant Interface Requirements (NPIRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements (NPLRs) and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities. The NPLRs are requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance or transient condition is important. It is essential that this process be followed closely in attempting to apply any new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant’s licensing and design basis. The safety of nuclear power plants is of paramount importance. 2) R1, R2, and R3 state “each” non-protection system equipment limitation. This should be clarified to state "each non-protection system equipment limitation associated with the applicable protection function." 3) Event monitoring equipment required by M5 will be a significant burden on GOs to only prove a negative. We believe M5 should be removed from the standard, because the benefits gained do not justify the costs.
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
LADWP agrees with this concept since no feedback signal is available (in an open loop control) to regulate against for Setpoint (Reference) control.
Yes
LADWP agrees with the guidance.
LADWP recommends that “technical justification” is defined and/or replaced with more specific language, i.e.: “Based on the latest round of industry feedback, the GVSDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly leading to model verification) only if documentation such as model structure and data values for the excitation control system demonstrates the ....”
Yes
LADWP agrees with this revision.
LADWP supports the language under Attachment 1, “Consideration for Early Compliance”.
LADWP does not have comments on this question at this time.
LADWP does not have comments on this question at this time.
LADWP supports the following comment below: “The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the

underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.”
Group
Bonneville Power Administration
Chris Higgins
The curve depicting the “no trip zone” for WECC in Attachment A is not consistent with the overfrequency and underfrequency requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan (Plan). A step is missing in the curve for the underfrequency requirements. The table representing the points on the “no trip zone” curve for WECC is also missing the same step as the plot. Additionally the presentation of the information in the table is confusing. As presented, the table specifies a time range of staying connected for selected specific frequencies. The table should specify a specific time for staying connected for frequency ranges. For example, as currently depicted in the table, a generator would need to stay connected up to 0.75 seconds (or between 0 and 0.75 seconds) at 57.0 Hz. The WECC Plan allows for instantaneous trips at 57.0 Hz. Further, the WECC Plan requires the generator to stay connected for 45 cycles (0.75 seconds) for frequencies greater than 57.0 Hz. but less than or equal to 57.3 Hz. This is not accurately reflected in the Table. The plot in Attachment A and the associated tables must be corrected to accurately reflect the requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan.
Individual
Russell A. Noble
Cowltiz PUD
Yes
Yes
No
Technical justification should also include reasonable demonstration that the improved model will improve the Reliability of the Bulk Electric System.
Yes
Cowlitz PUD respectfully disagrees with the use of the statutory term bulk[-]power system in the applicability section of any reliability standard. This term is not adequately defined to be used anywhere excepting arguments as to whether a proposed standard falls within the jurisdiction of the Federal Power Act of 2005. Use of the statutory term will hamper any future efforts to revise the Statement of Compliance Registry Criteria. The Bulk Electric System is a subset of the bulk-power system. If the intent of the SDT is to include any generation of stated MVA name plate capacity connected to a “transmission system” operated at an undefined voltage, the result will be to defeat

work being done to technically justify exclusion of certain bulk-power system facilities which have no substantial impact on Reliability. If however, the intent of the SDT is to follow the Statement of Compliance Registry Criteria and imply that the "BPS" is equal to the BES, it is preferable to specify generation connection voltage than use BPS. Cowlitz agrees that non-BES generation may need to be included in this standard's applicability section (as users of the BES), however specific generation that a particular GO may own which by itself would not have required registration of the entity should not be inadvertently included in the applicability of this standard.
No
Cowlitz is only concerned with the 60-day response time. The responding entity should be given some leeway to negotiate a delivery time if the 60-day response is not feasible. Otherwise, substandard estimates will be provided to avoid violation of the standard.
No
Cowlitz supports Clark County PUD's position. Please verify the following: The problem is that PRC-024 skips a frequency step in the low frequency operating area. The generator frequency ride through of Attachment 1 is inconsistent with the current WECC Off Nominal Frequency plan and the frequency ride through in the proposed WECC-0065 regional criteria. The PRC-024 ride through could cause a combustion turbine to operate at 58 Hz for a duration that would cause damage to the turbine blades. The current WECC ONF ride through avoids this.
Individual
Michael Goggin
American Wind Energy Association
Yes
Yes
Yes
Yes
Yes
Yes
Yes, the feedback we have received from wind turbine manufacturers is that, if such a standard were not applied retroactively and were implemented with a grace period extending at least several years into the future, wind plants would be able to meet these requirements.
Individual
Scott Berry
Indiana Municipal Power Agency
no comment
no comment
no comment
Yes
IMPA believes that the reference of "bulk power system" should be replaced with Bulk Electric System throughout the standard. Bulk power system is used in the Compliance Registery, but it is not a NERC defined term. FERC even agrees that bulk power system goes beyond the Bulk Electric System (FERC Order 693). IMPA is troubled by the requirement in R2.1.1 that requires a voltage excursion from a staged test or a measured system disturbance. Are there an ample supply of contractors or consultants that can perform such a test? What is the risk to a unit to perform the staged test?

No
IMPA does not agree that there would be any gain in reliability by requiring Generator Owners to give an estimate on the performance of a unit or the overall plant during a frequency or voltage excursion. Will such a request include specific parameters that would be expected on the system to narrow down this imposition of an estimate upon the Generator Owner? Will Generator Owners be capable of providing an estimate that may be required under this item? In addition, the Transmission Planner is to provide the dynamic simulation of the voltage and frequency profile at the point of interconnection. There is no guidance in the Standard as to how often or what means will be used to submit the (new) profile(s) to the GO – will it be annually, seasonally or?? IMPA also has concerns with attempting to accurately predict the ride-thru capabilities of a generating unit/plant on a consistent basis. As an example, if the unit/plant was operating during an extreme and prolonged period of heat and humidity it's characteristics and ability to ride thru a frequency and/or voltage event will be different than if running during the opposite – extreme cold and wind. Many of the unit/plant auxiliary systems may be located in areas that are not climate controlled and it would be extremely difficult to consistently predicte how they will react during temperature extremes.
No
Is the technology to meet this requirement even currently available to a newly built generating facility? To force such a requirement on newly built generating facilities at this time, one is speculating that the technology will be available. Can we risk reliability of the gird on such speculation (Generator Owners not building generating facilities because they cannot meet this requirement)? What if the technology is not available? IMPA believes that this standard will be reviewed by NERC in five years or sooner and at the time the SDT can revisit this possible requirement to see if the technology to keep a generating facility on line during a voltage or frequency excursion has been proven. Or a condition could be added that says new units shall be designed and built with the frequency and voltage excursion equipment if it is the industry standard, readily and commercially available and comes at competitive market prices.
This standard should concentrate on being a relay standard because it is not practical to include equipment limitations (excluding generator frequency and voltage protective relay equipment) that might trip the generating unit or generating plant offline. Just to figure out what the equipment limitations are at a generating plant an entity would have to perform a complete analysis and stability study on the generating plant including all auxiliary systems. If an entity cannot do this within it's organization, it will have to hire a contractor and/or outside consultant to inventory, test, and model the unit/plant. This type of analysis will be expensive and will come without any guarantees from the contractor that all the equipment limitations have been noted or discovered. In addition to the initial testing that a unit/plant will require to meet this standard, an entity will have to perform some type of routine testing and maintenance program in this area to ensure equipment characteristics have not changed enough to become a plant limitation (heat and age changes equipment characteristics). Based on this standard, entities will have to have equipment tested and built to certain specifications that will allow it to ride through a voltage and/or frequency excursion which will increase equipment and maintenance costs and could potentially limit equipment suppliers. One has to wonder if all of this cost will guarantee an increase in BES reliability that makes it worth paying for the work and equipment that will be needed for compliance (with the chance that the plant will still trip offline). In how many past instances has what this standard is trying to protect against been a proven issue? There term "power conversion control equipmen"t is not defined and will allow entities to apply this term to different equipment which may or may not be correct. The SDT should take the time to define it now and not allow a CAN to define it. Measure five (M5) is currently written so that it appears that an entity will have to purchase a Digital Fault Recorder(s) for the unit/plant in order to produce the evidence needed to show a unit tripped offline (i.e. frequency rate of change greater than 2.5 Hz/sec) outside of the "no trip" zone. IMPA does not agree with this philosophy since the cost to purchase and install DFR's can be costly, especially to smaller entities. Why is 5.2 allowed for new units but not existing units? In 5.6, what makes the Mitigation Plan acceptable? Who needs to approve or make the Mitigation Plan acceptable. Where is the Mitigation Plan defined? IMPA believes the word "acceptable" should be removed.
Individual
John
John Bee

Yes
No
The SDT needs to clarify and state that generating units will be able to use testing and verification data developed prior to the standard being approved and going into effect. Please consider adding text specifically stating this to the Standard itself similar to MOD-026 Attachment 1 that provides a “Consideration for Early Compliance” provision. Refer to MOD-026-1 draft revision 2 Section 6, “Consideration for Early Compliance.”
Draft MOD-026-1 R.2.1 requires that the Generator Owner perform verifications subject to include certain information as specified in sub requirements 2.1.1 through 2.1.6. R 2.1.1 requires that the unit model response is matched to the recorded response for a voltage excursion at the “point of interconnection”. For certain generating units the “point of interconnection” is on the high voltage side of the main power transformer (i.e., the switchyard disconnect switch). Because of this, the model would have to consider the impact of the main power transformer, auxiliary transformer, and auxiliary transformer loads all of which are not part of the generator/excitation system model. The Standard should be revised to state the response of interest is at the generator terminals and not at the “point of interconnection.” Typically individual synchronous machines have generator excitation control systems and do not have volt/var control systems. The text “and / or” or “as applicable” should be added to all references to “volt/var model” in the Standard and the associated attachments. With respect to the SDTs response to Exelon’s comment regarding the lack of acceptance criteria (refer to MOD-026-1 Consideration of Comments dated 2-23-12 pp 89-90), the following statements by the SDT need to be more clearly articulated within the body of the Standard. “It should be noted that the standard is written so that the Generator Owner “owns’ the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model’s predicted response.” The current draft (draft 3) of MOD-026-1 R.3 requires that a Generator Owner provide a written response to its Transmission Planner if the Transmission Planner deems the functional model is not “usable”, if there are technical concerns with the verification documentation, or if the model response did not match an actual event. This written response is to contain either plans for performing model verification, model changes or a technical basis for maintaining the current model. It appears from the comments of the SDT (see question 3 above) that the Generator Owner has final say on the model; however, if the opinion of the Transmission Planner differs from that of the Generator Owner there is the potential for a disagreement between the two entities. Given the potential for a dispute to occur and the lack of an “acceptance criteria” the SDT should consider adding in a provision for dispute resolution between the parties or clearly delineate that the GO has the final say.
No
The Frequency/Voltage Excursions should be limited to those listed in the standard, this should be explicitly stated in the requirement. 60 calendar days is an unreasonable amount of time to perform a study of this magnitude, suggest increasing the amount of time perform this study.
No
: It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the “no trip zone.” If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions.
The Off Normal Frequency Capability Curve should consist of separate tables for each Interconnect to make it easier to read. Exelon still feels that Footnote 1 belongs in the Applicability section of the standard. Suggest that the Applicability section be revised to state “GO shall set applicable protective relaying so as not to impact R1.1, R1.2, R1.3, R1.5 unless exempted by non-protection system equipment limitations per the exclusion criteria. It should be noted that even if a relay is not set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the “no trip

zone.” If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per the standard. An allowable tolerance needs to be included in the requirements in order to capture real world conditions.