Individual or group. (67 Responses)
Name (40 Responses)
Organization (40 Responses)
Group Name (27 Responses)
Lead Contact (27 Responses)
Question 1 (53 Responses)
Question 1 Comments (67 Responses)
Question 2 (45 Responses)
Question 2 Comments (67 Responses)
Question 3 (51 Responses)
Question 3 Comments (67 Responses)
Question 4 (57 Responses)
Question 4 Comments (67 Responses)
Question 1 (56 Responses)
Question1 Comments (67 Responses)
Question 2 (56 Responses)
Question 2 Comments (67 Responses)
Question 3 (57 Responses)
Question 3 Comments (67 Responses)
Question 4 (48 Responses)
Question 4 Comments (67 Responses)
Question 5 (47 Responses)
Question 5 Comments (67 Responses)
Question 6 (59 Responses)
Question 6 Comments (67 Responses)

Group
Arizona Public Service Company
Janet Smith
No
Yes
Yes
No
Yes
Yes
No
AZPS believes this question applies to R5. In any event, this requirement does not add anything to the reliable modeling since most GO(s) will be making a guess, and that does not make the simulation any more accurate. Additionally, the requirement for providing this information within 30 days is unreasonable. It should be at least 90 days. There is no reliability reason for requiring this data within 30 days. These are long range planning studies and modeling data is usually submitted on the annual basis.
No
AZPS believes this question applies to R6. There should be an implementation period for the requirement for new units to allow the plants which have been ordered already to not to have to be redesigned.
Yes

The measurement M6 for the new plant is not clear. One does not know how long a time it would take to get a significant event. M6 should be written such that if a unit did not trip for a system event, it will be considered compliant.
Group
Pepco Holdings Incand Affiliates
David Thorne
No
Suggest replacing the term “scheduled voltage” with “nominal operating voltage”. Voltage schedules may change over time, whereas “nominal” or “rated” voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, “rated” or “nominal” voltage.
No
Footnote 1 does make it clear that the Generator Owner is not required to have frequency or voltage protective relaying. However, in the current draft, reference to footnote 1 appears to have been inadvertently omitted following the phrase “voltage protective relaying” in R2.
No
Believe this question is referring to Requirement R5 not R4 as stated in the question. Not sure how useful the R 5.2 probability assessment would be, therefore suggest eliminating that requirement. R 5.1 coupled with the basis requirement in R 5.3 would appear sufficient to quantitatively assess the performance during voltage and frequency excursions. Also, see responses to question #6.
Yes
Believe this question is referring to Requirement R6 not R5 as stated in the question. 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. However, it is unclear how this standard would apply to the ride through capability of units connected to the BES, but whose source of auxiliary station service power is from a non-BES interconnection. Would the units also have to ride through expected voltage excursions at the point of interconnection with the station service transformer even if the station service transformer was not fed directly from the BES?
Yes
1) The applicability section from the previous draft of this standard should be re-inserted. Although the SDT chose to remove that section since the standard is intended to apply to all generation facilities that meet Compliance Registry Criteria, adding the specific generation criteria for which this standard applies within the body of the standard provides much more clarity than having to refer to a second document to define applicability. In addition, inserting the full applicability criteria would be consistent with the way Applicable Facilities are identified in Section 4.2 of PRC-019-1. 2) Requirement R 2.1.1 should be re-worded as follows: “For three-phase faults with Normal Clearing on transmission system facilities (lines, busses, transformers, etc.) adjacent to the point of interconnection, set voltage relays to ride through expected fault clearing times, not to exceed 9 cycles.” The use of the term “zone 1 faults” implies that zone 1 relaying schemes are always employed on the transmission system, which may not be the case. Pilot schemes, overcurrent schemes, differential schemes, etc. may be used instead. Also, the unit should stay connected if a fault were to occur on an adjacent bus or transformer rather than just on lines. Also, use of the term “Zone 1 fault” in Requirement R5 needs to be similarly addressed. 3) Requirement R 2.1.1 should also address ride through capability for TPL Category C contingencies (i.e. single line to ground faults with a stuck breaker, or other cause for delayed clearing) since generation units are expected to remain on

line during these contingencies as well. Granted, a three phase fault would be the most severe, however a single line to ground fault with delayed clearing times could also cause unwanted unit tripping, leading to a violation of Reliability Criteria. 4) The SDT in their response to comments on Draft #1 of this standard stated that “Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings.” This is fine for evaluating the response to three phase faults, or other balanced system disturbances. However, if it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with 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 phase to ground voltages could rise as high as 80% of the 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. requirement shown in Attachment 2. Generator voltage protection relays respond to actual phase voltages not just positive sequence voltages. 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 needs to be raised above 0.8 x 1.73 = 1.38 p.u. 5) The revised language in R3 referring to “the equipment limitation expires coincident with ….” is unclear and confusing. How can the “limitation” expire merely by the generating unit continuous capacity rating being increased > 10%. The Draft #1 version of this standard uses the phrase “the Generator Owner is granted an exception for that unit meeting the portion of R1 or R2 for that limitation once it provides documentation of the equipment limitation(s)…” “This exception for the equipment limitation shall expire coincident with…” The use of the term “exception, or exemption”, makes more sense and is more in line with the intent of this section. As such, the original language from Requirement R5 from Draft #1 should be re-instated. 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 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. 7) Comments on “Voltage Ride-Through Curve Clarifications” which appears on the last page of the standard: Item#1 - Suggest replacing the term “scheduled operating voltage” with “nominal operating voltage”. Voltage schedules may change over time, whereas “nominal” or “rated” voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, “rated” or “nominal” voltage. Item #2 - Suggest eliminating item 2. The ride-through curve is to ensure the unit remains on line for voltage excursions up to the limits defined by Attachment 2, regardless of the cause of the voltage excursion. Item #3 – The use of the term “cumulative voltage duration” is confusing since Attachment 2 is made up of a series of discrete allowable voltage magnitudes and durations. Also, the language only mentions voltage protective relaying and not other non-protective equipment, which could cause the unit to trip. Suggest re-wording as follows: “The generator shall remain connected (i.e., “ride-through”) voltage excursions caused by disturbances on the transmission system, when the voltage at the point of interconnection with the BES remains within the boundaries of these curves.” Item #5 d – suggest removing the term “scheduled”, making it read “d. Voltage is measured at the point of interconnection”
Group
Northeast Power Coordinating Council

Guy Zito
No
No
Any requirement that requires reporting based on a deviation greater than a specified threshold, that threshold should be included in that requirement, refer to R5 as an example. With those stipulations, those new terms are not needed.
Yes
No
The reference to “R4” in this question should be R5.
No
The refererence to “R5” in this question should be R6.
Yes
Yes
In R3, the SDT should review that generators are not required to provide a remedial plan for an equipment limitation. For the SDT’s consideration is the work done by and for the NPCC UFLS RSDT. It was recommended to retain the more conservative NPCC Frequency Capability Curve for setting generator protection as opposed to the proposed Frequency Capability Curve in PRC-024-1 for the following reasons: 1. Some portions of the NPCC Region have additional stages of UFLS set at lower frequency thresholds below 58 Hz. Adopting the curve in Attachment 1 may impact the effectiveness of the UFLS program from arresting frequency decline in these depressed frequency ranges. 2. As the numbers of distributed generators connected to the system increase, it is expected that overall generator frequency response is expected to be reduced. The distributed generation may also not need to comply with the generation trip thresholds as they may not meet the existing thresholds applicable to Generator Owners in NERC’s Statement of Compliance Registry Criteria. Adopting the proposed PRC-024-1 curve would jeopardize the survival of islands that may contain increasingly larger portions of distributed generation should the frequency decline below 58 Hz. 3. Adopting the proposed PRC-024-1 curve reduces the probability that the UFLS program will successfully arrest declining frequency for system conditions that are not addressed in NPCC’s 2006 UFLS Assessment. 4. Adopting the proposed PRC-024-1 curve would decrease the ability of an island to survive more severe conditions than those considered in the UFLS design (for example, islands with a generation deficiency greater than 25 percent).
Group
Westar Energy
Bo Jones
No
Yes
Yes
Yes
The applicability in this standard (≥100 MVA) is consistent with the applicability in MOD-027-1. However, the applicability in this standard is not consistent with MOD-025-2 and PRC-019-1. We propose that the SDT revise the applicability to be consistent between all of the standards included in this project.
No

We agree with the frequency excursion defined as +/-0.5Hz. We agree that ±5% is appropriate for normal operating conditions. However, this does not address contingencies or timeframes. The SPP regional criteria allows for a +5% to -10% change from nominal voltage on load serving buses under single contingency conditions. The Voltage Ride-Through Time Duration Curve in Attachment 2 does not appear to correspond with the proposed definition. The Voltage Ride-Through Time Duration Curve in Attachment 2 indicates that at 600 seconds, one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria states that we can operate at a +5% to -10% of nominal voltage on load serving buses during a contingency. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of this definition. We propose that the SDT consider defining continuous. We are unclear if continuous means from zero to infinite.
Yes
No
This question better addresses R5 rather than R4. We propose that the SDT team consider revising the 30 day requirement to provide documentation of the equipment limitation to 90 days in R5. We recommend that 90 days is a more appropriate timeframe for supplying this documentation.
Yes
No
We suggest that the SDT provide the technical justification for this time duration. We do not agree with the time duration of up to 600 seconds. This time duration appears to be significantly long for voltage recovery. From a planning perspective, 15 cycles or 0.25 seconds is standard for voltage recovery. Holding 0.9 from 3 seconds to 600 seconds could be difficult if there is full load on the unit. There may not be enough bandwidth before a loss of field relay occurs. If enough current is provided to the field, it will cause the relay to trip instantaneously. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of the attachment.
No
Individual
Edward Cambridge
APS
being intentionally left blank (no answer to be provided)
being intentionally left blank (no answer to be provided)
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Individual
Michael Goggin
American Wind Energy Association
No
Yes
Yes
No
Yes
Yes
Yes
Yes
New reliability standards should be accompanied by grandfathering provisions for existing generators and an implementation grace period of sufficient length to ensure that manufacturers have enough time to engineer their generators to comply with the standard and that generators for which purchase orders are already in the pipeline will not need to be re-designed. The grandfathering provisions and implementation grace period schedule that were included in FERC Order 661A should be sufficient to achieve those goals if they are incorporated into this standard.
Yes
No
Individual
Samuel Reed
Tri-State Generation and Transmission, Inc.
No
Yes
Yes
No
No
We don't think exceedance is a word. Suggest changing it to "operating outside of a continuous range of 60+/- 0.5 Hz". We don't agree with using the phrase "scheduled voltage" as is staed in the question, but the actual standard uses "rated voltage" with which we do agree.
Yes
Yes

Yes
Yes
Yes
The proposed WECC-0065 does not comply with the generator overfrequency curve.
Individual
Bob Casey
Georgia Transmission Corporation
Yes
Does Applicability 4.2.4 "Any technically justified unit requested by the Planning Coordinator" override the greater than 5% capacity factor over the last three calendar years statement in 4.2? It should in the case of units needed to prevent FIDVR problems and other peak hour considerations.
Yes
Yes
Yes
Should references to Planning Coordinator be changed to Transmission Planner (4.2.4 and R5)? Or, should Planning Coordinator be added as a functional entity? Have software manufacturers agreed to provide their models as described in R1?
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
Yes
Yes
THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
No
Yes
Yes
Yes
According to the standard this language is R5
Yes
According to the standard this language is R6
Yes

No
Individual
Hamish Wong
Wisconsin Public Service Corp
No
Yes
No
Synchronous condensers are installed at where they are specifically for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.
Yes
We have a number of questions and concerns as follows: • While the Standard uses the word "verified" and "verification" loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? • We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for excitation control was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Individual
Joe Petaski
Manitoba Hydro
No
Yes
No
Manitoba Hydro disagrees with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs,

STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators.
Yes
1)For Section 4.2 Facilities, the section should refer to 'BES Generating Units and Facilities' instead of restating components of the proposed BES definition. 2)Attachment 1 is not clear. Specifically, -the "Condition" in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be 'verified' and serve as evidence for multiple units meeting the conditions listed. -the wording for the allowance of a representative unit to be verified and submitted as evidence for identical units is not clear. -the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected 'with the verified model' which is incorrect. -We suggest the following. A statement that precedes the Attachment 1 table should be added that reads 'For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ' Row 1 should then be Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is ≤ 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.
Yes
Yes
Yes
No
While the requirement is technically achievable, justification should be provided by the drafting team for the curves in Attachments 1 and 2. It is not clear why the 'no trip zone' limits are set where they are.
Yes
Yes
Please provide justification for the curves provided in Attachments 1 and 2.
Group
ACES Power Members
Jason Marshall
No
Yes
Yes
Yes
This standard is highly administrative and full of compliance risks not associated with reliability. The purpose of the standard is to ensure that the GO provides an accurate model to the TP and ultimately to the PC. The requirements unnecessarily document the give and take that must occur between the GO and TP to produce a good model. R2, which essentially requires the GO to provide a good model,

is the only requirement needed. Everything else is just documentation related and unnecessary.
Yes
Yes
No
Requirement R4 references inquiries regarding equipment limitations that have been identified in R3. This particular question should apply to R5 instead. If applied to R5, the approach in theory seems reasonable.
Yes
R3 is an unnecessary requirement. Enforcement of R1 and R2 already create a de facto requirement to document limitations. Thus, R3 creates an opportunity for double jeopardy.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
Yes
The implementation plan call for a certain % of applicable plants to be in compliance over a certain number of years. Since plants may be registered individually, it is unclear what the term applicable plants is referring to in the implementation phase. Oncor takes the position that the reporting requirements for the Generator Owner as specified in R1, R2,R3,R4,R5 & R6 should be to the Planning Authority and not the Transmission Planner in the ERCOT Region. This would align with the current protocols, operating guide and planning guide that require the ERCOT ISO to be the primary interface with Generation Resources. The ERCOT ISO is registered as the Planning Authority. One option would be a regional variance that would point to the Planning Authority or Planning Coordinator in lieu of the Transmission Planner.
Yes
Yes
No
It is unclear as to what constitutes an estimate of performance.
Yes
Yes
No
Individual
John Bee on behalf of Exelon
Exelon
No

No
Differences between draft 1 and draft 2 of MOD-026 appear to be significant. Without reading through all 134 pages of comments and how the SDT addressed those comments it is too difficult to tell how the requirements were evaluated and if omissions were intentional or not. Suggest that the SDT prepare either a mapping document or a "redline to previous version" to illustrate changes and disposition of such changes to ensure there are no omissions from the prior draft.
Yes
Yes
Requirement R2 Exelon is in agreement that the Generator Owner (GO) should provide the generator excitation control system and plant volt/var control model and any necessary input data; however, the Transmission Planner (TP) should be the entity that is responsible for the model verification. Transmission Planning organizations have the expertise to implement and test the models in software, while the GOs have the necessary access to the equipment in the field. Most GOs do not have the software and the necessary personnel with the expertise to perform the modeling and model testing required by this draft Standard. Typically, TPs currently have existing software programs to run the excitation system models. The overall quality of the verification would be best served by having the TP that has knowledge in the model performance verse the GOs that do not have the current expertise in model performance or dynamic system response evaluations. Exelon also believes that the Standard should specifically define the acceptance criteria. If the acceptance criteria are left up to the GOs, then the TOs may have to deal with multiple acceptance criteria within a single Region. At the same time, a single GO may have to work with multiple TOs, which will lead to inconsistency if definition of the acceptance criteria is left up to the TO. Requirement 2.1.1 The Standard needs to provide specific guidance as to what criteria a voltage excursion from either a staged test or a measured system disturbance should be in regards to performing the verification. In addition, the SDT should provide specific examples of what types of staged tests would be considered acceptable. It is difficult to comment on the potential impact to the generating units (especially a nuclear generating unit) without knowing the criteria.
No
The definitions provided for Frequency Excursion and Voltage Excursion are not consistently applied throughout the Standard. Several of the uses of the term “excursion” (R1.2, R5.1, R5.2, R6, etc…) refer to the graphs in Attachments 1 and 2, which are based on time characteristics. Exelon agrees that 60 HZ +/- 0.5 Hz is reflective of a (normal) continuous operating band; however, the voltage +/- 5% is not necessarily a (normal) continuous operating band of "scheduled voltage". The "scheduled voltage" should be consistent with VAR-001 and VAR-002. VAR-001 Requirement R.4 states: "Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator." VAR-002 Requirement R.2 states: "[Unless exempted by the Transmission Operator] each Generator Operator shall maintain the generator voltage or Reactive Power output … as directed by the Transmission Operator." Suggest that the definition for Voltage Excursion is revised to state "an exceedance of system voltage beyond (i.e., outside) nominal operating band as determined by the Transmission Operator"
No
Footnote 1 should be added to 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 a non-protection system equipment limitation per the exclusion criteria in Requirement R3."
No
This question refers to Requirement R5 not Requirement R4. The "ride through" criteria should not extend beyond currently used critical clearing time (2nd zone of protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether nuclear units can survive anything beyond this. Plants with auxiliary power systems fed directly from the nuclear switchyard would be even more questionable as the transient is not shielded by the generator bus.
Yes

Most nuclear units will not be able to meet the time duration of "up to 600 seconds" unless they have an installed Load Tap Changer (LTC). This is due to the NRC required Degraded Voltage relay protection. The purpose of degraded voltage relaying is to protect emergency buses that feed equipment necessary for safe nuclear plant shutdown during an emergency or transient.
Yes
Applicability section and Requirements R.1 and R.2 Most nuclear power plants will not meet the requirements for frequency due to NRC required protection for Reactor Coolant Pumps and Reactor Protection System Motor Generator sets. In addition, most nuclear power plants will not meet the voltage requirements due to NRC required degraded voltage protection. Although a provision for exemption is permitted in R.3, Exelon requests that the SDT communicate with the NRC and with the FERC to ensure a conflict of dual regulation is not imposed on a nuclear generating unit without the necessary evaluation. Requirement R.3 second bullet The equipment limitation expiration should not be dependent on a capacity increase of the generating unit. An equipment limitation may be the result of NRC regulations and not the generating unit capacity.
Individual
Eric J Anderson
New York Power Authority
Yes
Yes
Yes
No
Yes
Yes
Yes
Yes
It is achieveable but signficant analyses must be performed. Undervoltage relay settings must be coordinated with the plant components most sensitive to system wide voltage excursions, particularly voltage drops. In some facilities, a POI voltage dip to 0.95pu would translate to a much larger drop within the local facility such that facility auxiliaries would start tripping due to the lower volatges on the facilities internal buses. The result is that even thogh the HV bus undervolatge relay is set to allow 0.95pu on the system the facility internal distribution may not be able to cope with voltage at that low a level. Nuclear power plants are particularly susceptible to low voltage conditions as unplanned tripping of a nuclear unit is to be avoided as much as possible. Nuclear units are also susceptible to overfrequency excursions as overfrequency causes motors within the plant to run at higher speeds. Nuclear reactor coolant pumps have overspeed limits due to core internals vibration limits that must be analyzed and coordiated with system overfrequency relay settings. These analyses typically take six to twelve months to complete and validate so a 12 to 18 month timeframe should be sufficient to implement the requirement.
Yes
No
Individual
Dan Roethemeyer
Dynegy Inc.

No
Yes
Yes
R2.1.1 does not specify the magnitude of the required voltage excursion, i.e. 1%, 2%, etc. Is their a specific required voltage change level?
Yes
No
Individual
Tom Flynn
Puget Sound Energy
Yes
No
Please clarify whether rate of change of frequency relaying is required; or alternatively, if the required setting of not less than 2.5 Hz/sec is only applicable IF rate of change of frequency elements are available and enabled.
Yes
Yes
This would require detailed information from the manufacturer of a combustion turbine. The requirement appears to be entirely reasonable for hydro installations. We expect it would take two years to complete this work.
Yes
No
Individual
Jeanie Doty
Austin Energy
No
Yes
Yes
Yes

ERCOT performs computer modeling based data (RARF) provided by Generators. Please consider allowing an exemption or alternate methods for older unit dynamic data as the information for these older units is not always available. ERCOT has used typical or generic modeling parameters for these units.
Yes
Yes
Yes
The curves in Attachment 1 are more restrictive than the current ERCOT Operating Guide requirements. The equipment impact of this new requirement requires additional internal review, before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
The equipment impact of this new requirement requires additional internal review before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
No
Group
Luminant Power
David Youngblood
No
Yes
Yes
No
Yes
Yes
No
Luminant believes this standard should only apply to voltage and frequency relay settings.
No
Luminant believes it may be technically possible to design a new generating unit or facility to ride through a low voltage event even though the cost to do so may be prohibitive and impractical. However, Luminant does not believe it is reasonable or achievable to expect the Generator Owner to be able to maintain those capabilities in perpetuity due to equipment deterioration and aging over time even though proper maintenance practices were implemented.
No
Luminant believes the settings are reasonable and achievable for relay settings only.
No
Individual
Michael Falvo
Independent Electricity System Operator
No

No, we are not aware of any. Similar to our comments on MOD-027-1, the Applicability Section of draft MOD-026-1 standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the “generating units” suffice to generally include all types of energy resources?
We are a bit surprised and disappointed that the SDT asks this question. The posted MOD-026-1 Draft 2 is a clean version, not a redline version from last posted, making it difficult for readers to identify where the previous requirements are contained in the revised draft. We understand that a reformatting may render tracked changes to be convoluted and hence a clean version may be a better option. However, in doing so, the SDT should provide a mapping document to show where the previous requirements are mapped into the revised draft standard. Whether or not any requirements were omitted could have been and should have been identified by the SDT through the mapping process rather than by the commenters.
We do not have an opinion on which standard should contain this as long as synchronous condensers are verified.
Yes
1. We do not agree with some of the requirements. i. R1: Standards should stipulate the “what’s” not the ”how’s”. To avoid the perception that the requirement is prescribing the “how”, we suggest simplifying the language of Requirement R1 by replacing “Instruction on how to obtain” with “Instructions for obtaining”. Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process. ii. R2.1: The phrase “models acceptable to its Transmission Planner” begs the question on what is deemed acceptable and what if the GO disagrees with the TP’s determination. To address the two issues, we suggest adding a requirement for the TP to specify the models requirements (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to “in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). iii. We are not sure why Requirement R5 is needed. First of all, it suggests that a Planning Coordinator may request the GO to perform a model review where the request can be technically justified. We wonder if the requirement really means “Transmission Planner” rather than “Planning Coordinator” since TP as the requester and model user is specified throughout the standard. Secondly, if it is indeed TP that was meant to be the requester, then would this request already been covered by Requirement R3? If not, what are the technical justifications? They are not specified in R5, unlike its R3 counterpart. Please clarify and/or revise the requirement as appropriate. iv. R6 stipulates the criteria that may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model. A computer model may fail to initialize due to reasons other than the submitted excitation control system and plant volt/var control function model itself; a no-disturbance simulation may not result in negligible transients due to other reasons; and finally, a 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 sub-requirements. We suggest this requirement be removed. Further, in many jurisdictions the setting and tuning of excitation control systems and associated power system stabilizers, etc. are determined by the Transmission Planners (or Planning Coordinators); the GOs would simply provide the equipment and set them according to the TP’s specification. In this standard, the responsibility is for the GO to verify that the model reflects the actual response of the tested equipment, whose settings have been determined prior by the other responsible entity. 2. In the previous posting, we provided 2 comments which in our view, have not been duly and satisfactorily addressed by the SDT and we would like to reiterate them here: i. We suggested that at a minimum, the generator's basic characteristics such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), voltage regulators, turbine-governor systems, etc. as stipulated in MOD-013 that support modeling for dynamic simulations should also be verified. A good excitation system model without a valid generator model will not provide the assurance that the

simulation results are valid, which may hurt reliability. In response to this comment, the SDT indicates that: “[it] agrees that appropriate dynamic models are needed for generators, exciters, PSS, and governors. The SDT believes that when testing personnel verify the excitation system model data, they also provide verification of the generator model data. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. The governor model is not verified with the excitation system model since it requires a frequency excursion. Verification of the governor model will be addressed by the MOD-027 standard. Experience indicates verification required by the MOD-026 standard often results in discovery of significant changes to the representation of the generator and exciter, suggesting that model verification provides significant reliability improvement.” Generator model parameters need to be verified based on tests conducted during both turbine/governor model verification as well as excitation system model verification. We are however not convinced that those tests that need to be performed during the excitation system model and data verification process, to verify certain portions of the generator model parameters will be conducted as a matter of course. We therefore reiterate our view that the verification of generation model parameters needs to be included within the scope of this standard and we urge the SDT to consider our comments again. ii. We suggested that in some areas on the interconnection, such as those that are sparsely populated, performance of generating units at less than 100 MVA might be critical to reliability. The criteria to allow the TP and PC to identify these units could include: a. A 5% or 10% deviation of any or several of the excitation system's parameters/settings could make an otherwise stable simulation to be unstable; b. Use of generic models for the excitation system or generator would make an otherwise stable simulation to be unstable. c. Other changes or incorrect assumptions for the excitation system or generator would make an otherwise stable simulation to be unstable. The SDT responded that: “After reviewing provided details, the SDT encourages you to review the new process draft (reference Requirement R2) and provide additional comments as appropriate.” Requirement R2 does not contain any provision that a TP (or PC) can request for model verification of units that do not meet the Applicability criteria. Throughout the standards, such a provision does not exist. This could leave room for system to exhibit unstable performance for reasons indicated in our previous comments. We urge the SDT to reconsider our proposal.
No
We generally agree with these definitions, but do not see the need to specify the band values, i.e. ±0.5 Hertz and ±5%, in them. The two definitions should stay clear of any specific values, which can be specified in the standard, to remain valid if and when the band values vary.
Yes
No
We believe the SDT meant R5, not R4, unless R4 is a sub-requirement or a part of R3 (which seems to be the case by the way R4 is worded) and a format error resulted in R4 becoming R5. We do not support the provision of 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 (which, by the way, should be modified as we suggest below), the TPs can apply the following relevant assumptions: a. For units that are equipped with frequency/voltage protective relays, the GO’s submitted relay settings will determine when the units will trip; b. 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?
Yes
First of all, we believe the SDT meant R6, not R5. Also see our editorial comments under Q3, above.

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 units to comply with the requirements. As worded, R6 does not contain this provision.
Yes
1. R3: Please clarify the meaning of the expression “non-protection system equipment”. Does it mean “a limitation imposed by equipment other than the protection system”? Or does it refer to generating units that are NOT equipped with frequency/voltage protective relays? In the latter case, how would the GO determine that the units that are not so equipped are unable to meet the criteria in Requirement R1 or R2? In our view, units that are unable to meet these criteria are those that are equipped with frequency/voltage protective relays and whose trip settings do not meet the criteria specified in R1 and R2 for specific technical reasons that are communicated to the Transmission Planners. For units that are NOT equipped with such protective relays, the suggestion that any of them may be unable to meet the criteria in R1 and R2 could be those which in the past have tripped before the thresholds. However, unless a unit repeatedly trips under like circumstances, isolated incidences do not provide sufficient evidence to arrive at a conclusive determination. And for those units that are NOT equipped with the protective relays and have never tripped before the thresholds, there is no telling whether or not they can meet the criteria. For the above reasons, we suggest the SDT to revise the R3 to convey the requirement that the GOs shall provide the technical reasons for not meeting the R1 and R2 criteria only for those units that ARE equipped with the protective relays and ARE set at different thresholds. 2. As indicated in our comments under Q3, we think R4 is a sub-requirement or part of R3 since R4 mandates the GO to respond to the listed entities within 30 days of receiving a request, and that in the requirement there is no mention of “what” the response should entail. The “what is stipulated in R3. 3. R7: We assess that this requirement duplicates with what we interpret as the intent of a good part of R3, i.e., to provide the listed entities with the settings of the frequency/voltage protective relays. Regardless of whether or not a GO is able to meet R1 and R2, it should be obligated to provide the generator protection trip settings to these other entities for modeling purpose (consistent with our comments under Q3). If a GO sets the protective relays at values that do not meet the R1 and R2 criteria, then it should be obligated to provide the technical limitations that form the basis of the deviation. This requirement thus should come after R1 and R2, and replaces the as written R3 for reasons that we mention in our comments in (1), above.
Group
Progress Energy
Jim Eckelkamp
No
Yes
Yes
No
No
PE suggests using the term “exceeding” rather than “exceedance”. PE furthermore believes that 60 HZ +/- 0.5 Hz is appropriate but does not agree that +/- 5% for voltage is an appropriate bandwidth for “normal”. Any threshold must agree with VAR-002. Along with a clarification of what a voltage schedule is (i.e. target, bandwith).
No
Requirement R1 subsection 1.5 is not clear as to when rate tripping is acceptable or not. Is it OK to trip at 59.6 Hz if the ROC is > 2.5 Hz or is this ROC trip acceptable only outside the no trip zone.
No
This appears to actually refer to R5. PE submits the comments below with the assumption that this question is directed toward R5: PE agrees with the requirement of R5 in general, but disagrees with the approach to the extent that R5.1 contains two options for GOs’ providing of information regarding

voltage excursions, one of which is problematic. Specifically, the requirements of Attachment 2 are too stringent and cannot be used by the majority of GOs, which leaves the second option as the only feasible method. The second option, provision of a voltage profile "at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault described by dynamic simulation provided by the Transmission Planner", puts the responsibility back on the Transmission Planner. Requirement R5 is intended to aid Transmission Planners in providing information on Generator models needed for Transmission Planning analyses, and yet as it exists the only option for provision of the information is a hindrance to Transmission Planners rather than an aid. PE requests that the SDT simplify the language to merely state that GOs have an obligation to provide information that the TPs request.
No
This appears to actually refer to R6. PE submits the comments below with the assumption that this question is directed toward R6: The ride through voltage profile in attachment 2 is not achievable for either new or existing facilities. The issue is not the relay protection but in the capability of the auxiliary equipment (such as motor contactors, coal feeders, instrument sensors). I do not know of any motor control contactor that will hold in when voltage goes to zero. The energy that is stored in the coil holding the contactor in place is rapid returned into the system during a time of fault. While the short circuit contribution of motors and contactors may last up to .2 seconds the majority of the stored energy is returned in the first 1/5 of the decay curve. The requirements that are specified in this standard are outside the IEEE and ANSI standards associated with manufacturing equipment used in power plants, while manufacturing of equipment to specialized standards MAY be possible the cost would be extremely high and in some cases may not be possible.
No
The ride through capabilities should be within the IEEE and ANSI C84.1-2006 "American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60Hz)". Standards associated with manufacturing electrical equipment
Yes
Forcing the utility to delay fault clearing (a three phase bolted fault at the point of interconnection causing a zero voltage) will increase the damage to the generation facility caused by the fault. Protective relay schemes have two primary objectives, to clear a fault rapidly to minimize the impact on the Bulk Electric System and to prevent (minimize) the damage to the faulted component and the components close to the faulted component. By forcing utilities to keep a generator feeding a fault of the magnitude implied by attachment 2 of PRC-024 the regulation may increase the costs of maintaining the generator. Additional inspections after a fault may be required to assure no internal damage occurred during the event that would not be required if the generator could be isolated from the fault more rapidly.
Individual
Dale Fredrickson
Wisconsin Electric
No
Yes
Yes
Yes
Section A Effective Dates: In 5.2.1, replace "30% of its applicable units" with "20% of its applicable units". There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years. Section B: Requirement R1: Replace "Each TP shall provide the following INSTRUCTIONS AND DATA to its GO…" with "Each TP shall provide the following DATA to its GO…". On the first two bullets, remove the phrase "Instructions on how to obtain…" The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace "Any of the GO's existing … model data" with "All the GO's existing … model data…". Since the TP already has this data, it is more straightforward to simply provide all

relevant data to the GO. Requirement R2: Replace the first sentence with, “Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models...” The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3. In R2.1.1, replace “Documentation demonstrating the ... model response matches the recorded response” with “Documentation WHICH MAY BE USED TO DEMONSTRATE that the ... model response matches the recorded response”. In R2.1.3, 2.1.4, and 2.1.6 replace “model structure” with “block diagram”. In Requirement R3, replace “90 calendar days” with “180 calendar days”, to allow more time to work through the technical challenges relating to these models. In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace “walk down” with “inspection”. Comments on Attachment 1: 1. Remove the note which says, “Note that local grid codes may specify...”. 2. Under “Conditions” for existing generators, it is not clear why there are references to both a ten year period and an eleven year period. Also, replace “Subjected to an activity resulting in an alteration of the response of the excitation control system” with “Changes to control system or parameter values”. 3. Under the exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under “Periodicity” for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis. Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.
No
The system can operate without problems within +/- 5% of nominal system voltage under normal conditions. Generator capability curves allow for continuous operation between 95% and 105% of rated voltage. Therefore, the operating band for voltage needs to be expanded beyond +/-5%, perhaps as high as +/- 10%.
Yes
No
(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Yes
1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its

protective relaying to avoid tripping ..."
Group
BC Hydro and Power Authority
Patricia Robertson
No
The Applicability section includes Generator Owners and Transmission Planners. If an entity is a Generator Owner, they will meet the NERC Compliance Registry Criteria including MVA criteria. Including phrases in section 4.2 such as “The remainder of the plant as an aggregate”, and “For all interconnections: Any technically justified unit requested by the Planning Authority” is confusing and it seems to be expanding the criteria. For example hydroelectric units that don’t qualify an entity as GO may be captured here. Also, for the aggregate, a GO may not be able to model and verify the aggregate consistent with the method used by TPs.
Yes
Yes
MOD-025 includes synchronous condensers. This doesn’t appear to be consistent with the strategy for MOD-026?
Yes
1. This standard is still not clear in terms of what constitutes verification of the model and what are related obligations of parties involved. Specifically, it is not logical or technically feasible to request GOs to address any problems with “usability” that TPs may have with the excitation control system model applied in their simulation software. Related Requirements are R3 and R6. The GOs provide accurate model data of their systems during the generator interconnection and facility registration process. Detailed base-line testing is done at that time. For subsequent verifications, GOs would use certain software tools, most likely not the same that the TPs are using, to simulate excitation control system response. This simulated response would be compared with actual equipment response. If traces (signatures) match closely enough, the model is verified. The GO would submit required information to the TP as per R2. At this point, the GOs obligations should be over and subsequently, the GOs should not have a compliance obligation to take part in resolving any issues that the TP may have with the “usability” of their models. Any further involvement by the GOs should be in the spirit of good will and professional courtesy among the parties. In conclusion, GOs should not have compliance obligations to resolve issues related to “usability” of models applied in the TPs power system simulation tool. 2. The idea that GOs “own” the models and are responsible for model modifications and verification still remains controversial for a number of reasons: a. GOs have little need for models and many do not have any expertise in modelling. b. Software tools used by GOs or external consultants for commissioning and verification purposes would not be the same as the tools used by TPs c. TPs would have to work on tuning so the whole exercise would not have a particular value in a technical sense. This is supported by the NERC Event Analysis & Information Exchange staff who noted during the first comment period: “Although verification (not validation) of generator equipment settings and testing should be the responsibility of the GO, validation of generator models response to actual system events should be done by the Reliability Coordinator.” Also, NERC’s white paper “Power System Model Validation”, Dec 2010, expands on this view. It implies that the ultimate responsibility for the usability and accuracy of dynamic models and how they perform in relation to the overall system model is the responsibility of the Transmission Planners, Reliability Coordinators or similar entities. 3. We recommend revising the wording in Requirement R2.1.1 for improved clarity. The way it is written, it strongly implies that the method of verification is based on system disturbance (ambient) monitoring: “Documentation demonstrating the unit or plant’s model response matches the recorded response for a Voltage excursion at the generator or plant point of interconnection. 4. Requirement 5 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner? Also, we recommend revising the wording in Requirement 5 for improved clarity. 5. Attachment 1 Column 6 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner?
Yes
Yes

No
The requirement R5 (R4 is a typo in the Question) is ambiguous and redundant. What does “estimating” mean? One could infer that the GOs are actually required to do what TPs are normally doing as part of their studies: estimating (assessing, simulating) the performance of units during frequency or voltage excursions. In order to fulfill requirements R1, R2 and R3 of this standard, GOs have to do engineering analysis and studies to develop adequate protection settings and to assess other non-protection systems and equipment. By declaring compliance GOs commit to keeping their units on-line during defined frequency or voltage excursions. In the case that a GO identifies a particular limitation, they would inform the TPs so that this limitation is taken into account in system studies. Hence, the goal of the standard would be fully met without R5. In light of the above, the requirement R5 should be removed. Technically it is of little value, if any, becoming just an unnecessary burden for GOs. In compliance terms it could be a source of perpetual confusion and disputes.
Yes
Frequency and voltage excursions specified in this standard are reasonable and actually less stringent then certain regional or area requirements. Generating facilities designed in line with industry practices and applicable standards should be able to ride through such disturbances. Lastly, it is in GOs best interest to have a robust design for new generating facilities.
Yes
Yes
1. R2 introduces Remedial Action Schemes (RAS) as an alternative description. We recommend keeping to Special Protection System and leaving RAS in the NERC glossary. 2. We recommend a consistent use of the terms Planning Coordinator and Planning Authority. In the Purpose of this standard, Planning Coordinators are referred to. In the NERC glossary, under Planning Coordinator it says “refer to Planning Authority”. The compliance registry list includes a column for Planning Authorities. The NERC Reliability Functional Model version 5 discusses Planning Coordinators only. Is the term Planning Coordinator going to replace Planning Authority?
Individual
James R. Keller
We Energies
No
Yes
Yes
Yes
Section A Effective Dates: In 5.2.1, replace “30% of its applicable units” with “20% of its applicable units”. There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years. Section B: Requirement R1: Replace “Each TP shall provide the following INSTRUCTIONS AND DATA to its GO…” with “Each TP shall provide the following DATA to its GO…”. On the first two bullets, remove the phrase “Instructions on how to obtain…” The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace “Any of the GO's existing … model data“ with “All the GO’s existing … model data…”. Since the TP already has this data, it is more straightforward to simply provide all relevant data to the GO. Requirement R2: Replace the first sentence with, “Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models…” The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3. In R2.1.1, replace “Documentation demonstrating the … model response matches the recorded response” with “Documentation WHICH MAY BE USED TO DEMONSTRATE that the … model response matches the recorded response”. In R2.1.3, 2.1.4, and 2.1.6 replace “model structure” with “block diagram”. In Requirement R3, replace “90 calendar days”

with “180 calendar days”, to allow more time to work through the technical challenges relating to these models. In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace “walk down” with “inspection”. Comments on Attachment 1: 1. Remove the note which says, “Note that local grid codes may specify…”. 2. Under “Conditions” for existing generators, it is not clear why there are references to both a ten year period and an eleven year period. Also, replace “Subjected to an activity resulting in an alteration of the response of the excitation control system” with “Changes to control system or parameter values”. 3. Under the exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under “Periodicity” for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis. Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.
No
Yes
No
(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Yes
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Individual
Linda Horn
We Energies
No
Yes

Yes
Yes
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No
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Yes
No
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Yes
1. The Applicability of this standard should be specifically stated to be limited to generators connected

at 100kv or above, as in the Registry Criteria. 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..."
Group
SERC Generation Sub-committee (GS)
Joe Spencer - SERC staff
Yes
The GS is not responding to MOD-026
Yes
The GS is not responding to MOD-026
Yes
The GS is not responding to MOD-026
Yes
The GS is not responding to MOD-026
No
The SERC generation sub-committee (GS) believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to "… exceedance of system voltage beyond the applicable voltage schedule."
Yes
The GS recommends that the applicability section be revised from "GO" to "GO's that have frequency and voltage protection functions activated to trip a new/existing generation unit." Also, while the GS does, in general, agree with the content of footnote #2 on page 2 (under R1), we believe that this is verbiage is better placed in the implementation plan because it puts commercial considerations into the standard.
No
The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
No
This appears to refer to R6. The proposed bands would need to 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 designs and no concerns were identified. However, It is 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.) have been and are 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 less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
No
Comments: The GS proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
Yes
During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: • Important Existing nuclear plant settings are inside the published no-trip bands • How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. • Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform it's function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2. “The comments expressed herein represent a consensus of the views of the above named members of the SERC Generation Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Group
Idaho Power - Power Production
Tim Brown
No
We agree with the need to include wind generation in this standard, however the applicability section seems to be overly complicated. We do not see the relevance of the 80% of connected generation as discussed above. We believe that the NERC generator registry/ BES criteria would be clear and appropriate continent wide for this standard and with many other standards. In addition, we believe that Section 4.2.4 is too open-ended. It appears to open the door for the verification of any sized machine that does not match a response, or for other open-ended reasons. Too open-ended and subjective.
No
Yes
The Requirements direct the GO to send responses, data, inquiry to the Transmission Planner. Should this really be to the Transmission Operator? We understand that the TP will ultimately use the data, however, we believe the data and communications should flow through the TOP. Specifying timeframes for both recording data and providing results is cumbersome. More properly, timeframes

and periodicity should be specified only on providing results. If necessary, a limit on the age of the recorded data could be specified. R6.1, R6.2 and R6.3 seems overly prescriptive and of little value. In the process of verifying model data and comparing to recorded results, those 3 conditions are met. If the Transmission Planner has concern about their ability to use the model data in their studies, it is more properly addressed either without specific criteria, or with the specific criteria that the Transmission Planner is unable to reproduce the simulated response contained in the model verification. The requirement of several responses to submit plans to test within 365 days and submit with 180 days (per the periodicity table) seems too long from an system reliability standpoint, particularly where it is the outcome of an observed response to an actual event not matching the predicted response. On the other hand, scheduling a test and model verification within a shorter period of time would be challenging for the GO, particularly those that rely on outside contractors for the model verification work. Any request to verify or retest due to an observed response not matching an actual event should be accompanied by full electronic information (recorded data, simulated output, simulation conditions, model data used by TP). Requirement R1. The first two bullets appear to allow variation between Transmission Planners on acceptable models and software. The list of acceptable models needs to standardized at least across the RRO. In addition, the GO should not need to adjust the model validation and verification work based on the software that the TP uses (what happens when the TP uses multiple software packages?). If the SDT feels there is a need to specify acceptable software, then that should also be standardized. The third bullet should read “All of the Generator Owner’s existing” instead of “Any”. The TP should provide all the information in its database regarding the GO’s facilities, not just “any” piece of it. R2, 2.1. Reference to “models acceptable to its Transmission Planner” is inappropriate, see previous comment. The list of acceptable models needs to be standardized, although situations (rare) where the Generator Owner and Transmission Planner jointly agree to use a model not on the list should be allowed. In particular, the Transmission Planner should not restrict use of any the models on the standardized acceptable list.
No
Basing the voltage excursion definition on scheduled voltage is troublesome, as “scheduled” voltage can change over time, and in some cases, varies seasonally. Protection and limiter settings are not, and should not, be adjusted to address varying schedules. That said, simply using nominal voltage instead of scheduled voltage is probably not the answer either, as it is not unusual to have POI scheduled voltages of 1.05 pu or higher.
Yes
Yes, R1 and R2 do make it clear that the GO does not have to install or set these functions however we believe that the standard should clarify better that the standard is applicable to all “voltage-based” protection functions such as the backup impedance function (21) and the voltage controller (51C) or voltage restrained (51V) Overcurrent functions. These functions may operate if not coordinated properly. We do not believe that was made very clear. Particularly for units that fully compliant with this standard, providing an estimate of unit performance during a frequency or voltage excursion is burdensome and unnecessary. If the event is within the parameters of the standard, the planner can rely on the unit staying on, if not, the planner should model the unit as a trip. In particular, we are unaware of any methodology that would be capable of providing an “estimated probability”. Protection consistently operates as designed and configured.
No
This requirement should not exist. Generator Owners are required to comply will all approved NERC and RRO standards. It is the responsibility of the Generator Owner to see that the plant is built according to specifications which should include all approved NERC Reliability standards governing power plants.
Yes
Yes
In section 2.1.1, we believe that the “three phase transmission system zone 1 fault” should be clarified. Is the zone 1 referring to the generator relay backup zone 1 element? The zone 1 element of the interconnection station line protection relays? Shortest line? Longest line? Another zone 1? Also, the language was a little confusing, is this an if-then statement? Since the voltage ride through curve apparently applies to all conditions (both operating and various fault configuration), reference to the

“three phase transmission system zone 1 fault” implies a limitation to applicability that is not intended, and the reference should be deleted. For R3, because the time horizon for this standard is long-term planning, we believe the 30 day communication requirement is not necessary. We believe 180 days is more in line with other reporting time frames with modeling related standards. We also believe that the equipment limitation expiration section is not needed. A simple statement stating that the when the limitation is no longer valid, the RC, PA, etc should be notified. For R6, we believe it is unnecessary to have different requirements for existing and new units. We do not see the need for performance requirements for new units. We believe this standard should be a relay settings standard, with generator performance being considered in modeling standards. R7 is burdensome to both the Generator Owner and to the receiving entities, and also prone to causing confusion. The entities proposed to receive the protection settings (RC, PC, TO, TP) would face a difficult task to be able to properly interpret the relay settings sent. The Generator Owner is the proper entity to determine the relay settings to remain in compliance with the standard. In addition, the requirement to transmit the settings within 30 days of changes is burdensome and unnecessary. Draft PRC-019-1 properly address the issue of coordinating settings with machine capabilities, and PRC-001 properly addresses the issue coordinating settings with the TO.
Group
Westinghouse
Scott Sweat
No
Yes
Yes
No
Yes
Yes
No
a. This is for requirement 5 not requirement 4 b. We cannot evaluate the performance of units during frequency and voltage excursions at the transmission interface point, only at the generator and 6.9kV bus level where the auxiliary equipment interface exists. Therefore, the frequency and voltage excursion profiles would be different than those submitted by the RC, PC, TO or TP. Also, 30 days is too short to perform a detailed analysis on plant performance during the frequency or voltage excursion. Further evaluation would be required for the transformers, turbine and auxiliary equipment to determine satisfactory operation in the long time periods encompassed in the "No Trip Zones".
No
a. This is for requirement 6 not requirement 5 b. It is uncertain that the requirements, when translated to the 6.9kV AC distribution system and below, can be achieved with the equipment installed in new generating facilities. Most motor specifications do not require demonstrated operability below 75% motor rated terminal voltage or >5% deviation in rated frequency. Additional vendor testing would be required in order to effectively demonstrate equipment design capabilities. Additionally, plant performance has not been evaluated for the entire range of frequencies in the "No Trip Zone". More analysis would have to be performed in order to verify acceptable plant operation in these frequency bands.
No
Due to the excessive duration of the +/- 10% voltage excursion, it is uncertain that many new manufactured turbine generators will be able to meet the V/HZ limits set by the manufacturers. Detailed studies would need to be performed to determine the ability of newer turbine generators to ride through these conditions.

No
Group
SPP Reliability Standards Develpment Team
Jonathan Hayes
No
Yes
Yes
We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
Yes
The applicability of 100 MVA matches MOD027-1 but is inconsistent with MOD025-2 or PRC 019-1. We feel like these should be consistent in every standard included in this project. VSLs for R4 footnote reference needs to be deleted since there is no footnote to reference. We would like to see a more consistent approach to the comment forms and the standard itself. It seems there is room for clean up in the posted standard/comment form.
No
We believe that +-5% is ok for normal operating conditions but this doesn't address contingencies being taken or a time frame. The curve in attachment 2 doesn't seem to correspond with the definition as proposed. We are also unclear about the term continuous. We think this means from 0 to infinite. This graph indicates at 600s one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria shows that during a contingency we can operate at a +5% -10% bandwidth.
No
We agree that R1, with the footnote mentioned, makes it clear that the Generator owner would not be required to have protective relaying installed or set for these functions. As for R2 we feel that footnote 1 should also be referenced in R2.
No
The question should mention R5 and not R4. We feel like the planners shouldn't have to request this data and should be supplied for each unit once and again if the characteristics change. We also feel like 30 days might not be appropriate time to gather such information and would suggest that 90 days would be a better time frame for supplying this data.
Yes
Question should read R6 not R5. We feel that as long as everyone knows about these requirements ahead of time that there shouldn't be an issue with achieving these requirements.
No
We would like to see the technical background/justification of why the timeframe of 600s was chosen. We understand seeing the reasoning to expand it from 4s, but 600s (10 Minutes) seems extremely too long for voltage recovery. From a planning perspective 15 cycles (.25seconds) is standard for voltage recovery. Holding .9 from 3s to 600s could prove difficult if full load on unit and might not be enough bandwidth before you hit a loss of field relay. If enough current is provided to the field it will cause this relay to trip instantaneously. Not sure that taking a 10% hit during this instance will work.
Yes
Would like to see a more consistent approach to the comment forms and the standard. It seems there is room for clean up in the posted standard/comment form.
Group
MRO's NERC Standards Review Forum
Carol Gerou
No
Yes

No
Synchronous condensers are installed at locations where they are specifically needed for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.
Yes
We have a number of questions and concerns as follows: • It is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? • If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? • We have concern about whether this Standard is cost effective for the industry. The transient stability dynamic modeling for excitation control was traditionally developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts required by this standard are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more. • MOD-026 does not account appropriately for the differences between distributed generation and single shaft generation. Aggregate generation that do not have a common excitation and regulator control system (such as wind farms) may pose serious difficulties in meeting system disturbance and / or staged testing. A staged test can be performed for a single shaft unit. However, wind farms may not have a centralized plant or wind farm voltage controller. If that isn't the case, entities may be forced to actually shock the BES to force a disturbance large enough to force a wind farm response. If this is true, then exceptions need to be made. • In addition, there are concerns about the technical development and accuracy of current wind farm models. It is not certain that all manufacturers have fully developed all of the control system models necessary to meet these standards. Type III and Type IV PSS/E generic standard models have all been benchmarked. What has not been included in these models are the wind farm park voltage controllers. While local turbine model controllers will dominate the short term response, the longer term park voltage controls are not represented. Therefore if the models aren't available, then model traces can't accurately match reality. Older wind farms will not have appropriate models. In short, the state of wind farm models hasn't completely developed to match wind farms and specific exemptions for wind farms need to be added to the standard at a minimum.
Yes
No
The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under R3 which covers equipment limitations either.
Yes
This question seems to be referring to R5 rather than R4.
No
If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Yes
Do not have an alternative value to suggest.

Yes
It is not clear what the basis for the requirement of R3 with regard to a 10% or more increase in capacity would lead to an expiration of an equipment limitation as the change that results in the capacity increase may not be related in any way to the origin of the equipment limitation.
Individual
Jon Kapitz
Xcel Energy
No
Yes
Yes
No
Yes
Yes
Yes
Yes
It is Requirement R6 that requires new units to ride through excursions. We believe it is technically feasible to design generating units to reach a high probability of riding through these excursions. However we do not consider the additional expense necessary to meet this objective to be of value to our customers given the infrequency of occurrence of excursions of the magnitude described in this standard. Excursions of this type have occurred on our system and some generating units have tripped due to the excursion, but it has never led to a cascading outage. In addition, we believe new plants should not be considered in violation for a trip during an excursion if the GO can identify the reason for the trip and correct the deficiency. If the standard is made mandatory, we believe that an additional five years should be allowed for new units so that the A/E firms can develop proper design criteria for plant auxiliaries and equipment OEM's to develop designs that can handle the requirements
Yes
No
Individual
Michael Brytowski
Great River Energy
No
Yes
Yes
Yes
We appreciate the drafting team's consideration in Section A.6 to allow a unit that has already verified its excitation system to be considered compliant. However, it is not clear how this section helps. How does the Generator Operator demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff be sufficient? Will the regional

entities be willing to validate that they have confirmed regional criteria? This standard is overly administrative by memorializing the interactions between the Generator Operator, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck. They are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are needed to accomplish the purpose of this standard. They are: ne requirement for the Generator Operator to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6. This just represents one of the issues with memorializing the interactions between the Transmission Planner, Planning Coordinator and Generator Operator in the standards. Because the tests to verify the excitation model can be expensive, there should be a demonstrated need to perform a test. 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. That does not even include opportunity costs from lost energy sales should the test cause the unit to trip. Thus, if there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the generator operator should be able to wait for a system disturbance appropriate enough to verify its model. Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Operator should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.
Yes
No
The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under R3 which covers equipment limitations either. It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why?
No
Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the Generator Owner's best interest to be responsive. Thus, this requirement is not necessary.
No
If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Yes
Yes
It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The

red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the “clean” documents. Thus, it is not clear what is being voted on. For example, the “clean” document shows that there are five parts with Requirement R1. The “redline to last posted” document has four subrequirements under the main requirement R1. The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point. Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
No
Individual
Greg Rowland
Duke Energy
No
However, an exception should be made for variable energy resources for which models have not yet been fully developed and accepted. Techniques for validation of these devices have not been developed similar to generator excitation model validation tools (EPRI PPPD).
Yes
No
These types of reactive resources should be included if of a sufficient size to impact reliability.
Yes
1) If System Models are poor today, it is probably due to a lack of understanding on what models are required, setpoint control and what changes need to be communicated to Transmission when plant projects are done. Periodic reverifications are probably not the right way to ensure reliability. Instead there should be an event-based revalidation requirement, such as if you replace the control system or recalibrate the control settings on an existing unit, replace the rotating exciter or rewind a generator. An approach where there is an initial validation effort to get today’s models consistent with installed equipment is clearly needed. However, assurance that future models will remain valid requires that there is a program in plant project processes to revalidate when appropriate, and thus a requirement to show that the company has the needed project processes and has followed that process is the right way to approach this. 2) There needs to be a requirement for the entity responsible for actually

inputting the models and data to do so on a timely basis. This should be an annual update of data to be submitted to the interconnected models. As currently written, there is a requirement for the GO/GOP to submit information, but they do not input directly into the interconnected system models. MOD-010, MOD-011, MOD-012 and Mod-013 don't currently ensure that data is incorporated in a timely fashion. 3) Since GO/GOPs do not always have electrical system modeling expertise, nor participate in interconnected system models groups such as the MMWG which sometimes changes how equipment is modeled, there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF are considering a collaboration to do so. 4) 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. 5) Discussions during the EPRI PPPD users group indicate certain parameters in the models are temperature sensitive, and thus verification and adjustment of models should be done under conditions that reflect normal operating conditions. An on-line voltage step test or DFR data from an event is the best way to perform the validations. It's not clear if validations against off line tests would actually make the models worse, but the industry should be encouraged to do validations on line near full power. 6) R2, 2.1.3 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. 7) Footnote 4 – Delete the phrase "or evidence that the simulated unit or plant response does not match measured unit or plant response". Otherwise this standard could be made applicable to a small unit that has no impact on reliability.
No
We are not sure what is the purpose of the voltage excursion definition in this standard. Is excursion measured versus scheduled voltage, or equipment rating?
Yes
No
Should be R5. We question the value of this requirement, and how the TP use the probabilistic information in any TPL analysis. It's unclear how compliance with planning requirements would be demonstrated. The planner needs to know under what voltage/frequency conditions a unit will trip so that when those conditions are attained in the model the unit will be turned off. Generator owners/operators need to make their best efforts to determine the conditions and provide it to their TP's, updating the information as plant design changes occur or operating history indicates the conditions have changed. Having a time estimate as specified in R5.1 does not provide the voltage/frequency threshold that the planner must know so that the unit can be tripped when those conditions occur in the model, no matter what time those conditions occur.
No
This appears to refer to R6. 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). It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
No
The LVRT portion of the curve between 0.4 seconds and 3.0 seconds should be 0.90 voltage PU. Electrical powered devices at the plant will begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Yes
During the drafting process, quite a bit of feedback was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated, using the allowed operating bands developed as a setting coordination. The concerns include: • Existing nuclear plant settings are inside the published no-trip bands • How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. • Why is a voltage ride-thru criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be long enough in duration for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar restrictions may also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC Reliability Standard NUC-001-2. PRC-024-1 should allow nuclear power plant interface requirements to be managed under NUC-001-2. (See PowerPoint and AREVA white paper provided to the SDT).
Individual
Melissa Kurtz
US Army Corps of Engineers
No
Yes
Yes
No
No
Yes
Yes
No
R5 applies to existing units. This requirement seems vague and subjective - recommend clarification. Please clarify the term "less stringent" - do you mean 'in the no-trip zone' or 'outside the no-trip zone. How will the information be used and what are the implicatios if the response is not satisfactory? R6 applies to new units - I have no comments on R6.

Yes
Yes
-R2.1.1 - 'not to exceed 9 cycles' this wording is confusing and needs to be clarified. -Suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity included in MOD-026, Requirement R3. -R7 seems to be a duplicate requirement with PRC-001 - Implementation comment - from an implementation perspective it would make it easier if all standards in Project 2007-09 had the same implementation schedule.
Individual
Steve Rueckert
Western Electricity Coordinating Council
Yes
Requirement R1, first bullet. Grammatically, should the word model in the first bullet be models? Requirement R4 requires the Generator Owner to provide revised model data or plans to perform model verification. The way I interprete the wording of Requirement 4 is that the model data or plans to perform model verification are due within 180 calendar days. If the GO provides plans to perform model verification and submits the information on their plans within 180 days, is there any time limit as to when the model verification must be performed? If so I suggest it should be included in the language of the Requirement. If the actual verificatio must be done within 180 days this should be clarified becasue right now it just looks like only the plans have to be submitted within 180 days.
No
WECC is requesting a regional variance to Requirement 1 that reflects the generator performance requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan. WECC's continuouse operations zone is between 59.4 hZ and 60.6 Hz. Therefore, WECC will need a regional definition of Frequency Excursion to be an exceedance of system frequency beyond a continuous operating band of 60±0.6 Hertz.
Yes
No
The question above appears to be referring to R5, not R4. R5 has the requirements for providing estimates of the performance of the units. I have no comments on R5, However, I have the following comment on R4. We agree with the intent of the requirement, but believe that more specificity in what is required in the written response is necessary. As written it could be argued that a simple response from the Generator Owner indicating they received the inquiry was sufficient. Suggest adding detail similar to that included in MOD-026, Requirement 3 that identifies what the response must contain.
For the WECC variance we would need a revised Attachment 1 that also shows the WECC No Trip Zone or an additional Attachment to illustrate the WECC variance No Trip Zone. WECC also requires modified language to R1 and the parts 1.1-1.5 to reflect the WECC variance. Requirements R5 and R6 will need to be modified to identify the appropriate Attachment for the WECC variance.
Individual
Kathleen Goodman
ISO New England Inc.
Yes
Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These

generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? The applicability criteria in this standard should be the same as the registry requirements.
Yes
Yes
This standard may lead Generator Owners to violate another NERC Standard; this standard implies in requirement R4 along with footnote 6 that Generator Owners could have 180 days to notify its Transmission Planner that an AVR status has changed. The VAR standards require notification within 30 minutes of a change in AVR status. Requirement R4 is also a direct violation of the ISO/FERC Tariff Section I.3.9 that requires generators to provide information prior to making material changes to equipment characteristics. Allowing generators to make changes such as these without prior review represents a significant reliability concern. MOD 26 needs to clearly state that non-proprietary models need to be provided by Generator Owners, otherwise a major reason (NERC MMG) for model collection will be undermined. As written, the intent of requirement R2.1.1 is unclear. How are stabilizers and excitation limiters to be addressed? How large does the voltage excursion need to be? This requirement needs to be made much more specific. With respect to requirement R1, the standard should allow user models to be provided. The second bullet point implies that models would only be allowed from a list of standard models. User written models may provide more accurate representations of actual equipment installations. However, these models cannot be proprietary and must be able to be distributed. In requirement R5.2 bullet 1 – generator owners should not be providing generic model data. In requirement R5.2 bullet 2 – what constitutes a “walk down” of the equipment? Suggest replacing with “Updating parameters based on actual field verification of equipment settings.” This standard should indicate what constitutes the excitation system and should indicate that it includes a power system stabilizer and limiters. This standard addresses existing generators, but should also address new generators. In regard to the Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas with very little verification for up to ten years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within it’s area.
No
The term “system voltage” is unclear as to where it is measured. Attachment 2 shows the curve based on voltage at the Point of Interconnection, yet R2.1 refers to voltage at the generator terminals. ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the “Point of Interconnection–Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. The time duration curve shown in Attachment 2 will need to modified to be consistent with this range for the times at and beyond 600 seconds to be consistent with this change.
Yes
Yes
The RC/PC/TOP/TP functional entities provide for a wide-area view of the transmission system and its operating limitations. These entities need accurate generator characteristics in order to correctly plan the system and to operate it within known limits.
Yes
ISO-NE has frequency data from all generators operating within the New England footprint demonstrating, with the exception of certain nuclear plants and some smaller and very old generating units, that all generators can operate to meet the under-frequency curve depicted by PRC-024 – Attachement 1, and, in fact, can and do meet our more stringent underfrequency requirements. Within the NPCC Region existing requirements for generators have been in place for many years that are more stringent than the underfrequency curve shown here. The NPCC more stringent requirements have been shown by studies to be necessary to support a viable automatic unferfrequency load shedding program. It is our position that generators within NPCC will be required

to continue meeting these more stringent requirements independent of the approval of PRC-024-2. New generating units should meet all the PRC-024-2 requirements at the time of their interconnection or in-service date. No special implementation plan should be afforded these units beyond the regulatory approval date of the standard.
Yes
Although the time duration is acceptable ISO-NE does not agree with the band shown. See our comments on Question 1, above.
Yes
Comments are provided by ISO-NE on the following requirements: R2.1. This requirement specifies when operating (within the band specified) of rated terminal voltage (VT) and during the transmission system operating conditions defined in PRC-024 Attachment 2 .... ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the “Point of Interconnection–Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. as suggested in our comments on Question 1 above R2.1.1 infers that the standard is to base the voltage relay settings on actual fault clearing times. The standard should be 9 cycles. As the system changes, clearing times may change and then problems with an existing generator who has set its relays to the actual clearing times may be an issue. Changing this requirement would also require a change in the curve shown in Attachment 2. If this comment is ignored, as an alternative ISO-NE suggests that R2.1.1 be modified to state, “For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, plus margin, not to exceed 9 cycles.” This is suggested to direct the setting of relays in a manner that will prevent a relay race that could trip the generator sooner than the actual fault clearing time. R2.1.3 appears to provide a way to get around the intent of the standard. If a generator cannot meet the requirements of the standard, they could put in an SPS to trip the generator and avoid meeting the intent of the standard. This has the potential to lead to a proliferation of SPSs. Notwithstanding the concern over R 2.1.3, R2.1.3 and R2.1.4 should be rewritten as follows: 2.1.3. If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relays to trip the generator even if [voltage is] in the “no trip zone” in PRC-024 Attachment 2 is acceptable [provided that the voltages will not enter the trip zone for criteria faults that do not initiate the SPS or RAS]. 2.1.4. If clearing a system fault necessitates disconnecting a generator, then setting relays to trip the generator even if operating [voltage is]within the “no trip zone” specified in PRC-024 Attachment 2 is acceptable. 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. R5 appears similar to R3 in that the generator is only required to document if it trips in the “No Trip Zone”, rather than correct the issue. Exceptions in 6.1.1 and 6.2 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-024-2 without exception. In general, R6 and sub-requirements R6.1 through R6.7 introduce a number of conditions and exceptions for new units that are unnecessary and cumbersome to monitor. Some of them represent common sense conditions, such that if they were to occur, an auditor would be able to deem the entity to be in compliance since it is not posiible to comply with the letter of the requirement. However, there are many more cases that could be listed and you will never capture all possibilities here. Overall R6.1 through R6.7 should be deleted. As the system changes, the requirements will change. The machine should be properly designed upon installation to allow the necessary flexibility in the development of the transmission system over time.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Yes

Yes
Yes. There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Yes
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. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES voltage response – and have already the recording equipment needed to validate performance.
No
Ingleside Cogeneration LP agrees that the continuous frequency specification is unambiguous and reasonable. However, the voltage operating specification needs to tie directly to the Transmission Operator's voltage or Reactive Power schedule developed in compliance with VAR-001. We believe this was the drafting team's intent, but the definition does not clearly indicate that this is the case.
No
Requirement R1 from Ingleside Cogeneration's perspective could lead to a double-infraction for the same incident. For example a single improper relay operation for an underfrequency transient would lead to a violation of both R1.2 and R1.3. It should be sufficient to specify that relays must be set in conformance with the off-frequency excursions provided in PRC-024 Attachment 1. Also, there must be some logical limit to the Hz/Second ride-through threshold specified in R1.5. As the requirement is written, even a large-magnitude frequency transient must not cause relays to operate as long as the frequency rate of change is slow. If for example, the interconnection frequency dropped to 55 Hz at a rate lower than 2.5 Hz/Second, R1.5 seems to require that the generator would remain connected to the BES. For the record, R2 seems to be more logically constructed – and lists reasonable exceptions to voltage relay settings. Ingleside Cogeneration LP recommends the drafting team to take a similar approach on R1.
No
Ingleside Cogeneration LP assumes this question actually applies to Requirement R5. It is not clear what extra reliability information will be provided to Transmission Planners as long as Generator Owners confirm that their voltage and frequency settings comply with the performance curves in the attachments. It may be valid to require an estimate of performance if the GO identifies a limitation as allowed under R3. Otherwise, the TP should assume generator relays will operate if the magnitude and duration thresholds defined in the attachments are exceeded.
Yes
Ingleside Cogeneration LP assumes this question actually applies to Requirement R6. The frequency and voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view.
Yes
The voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view. Existing facilities that cannot meet this specification must be able to document an equipment limitation as allowed in R3.
No
Individual
Brad Jones
Luminant Energy
No
I am not aware of any other generation configurations/types that should be covered in the Applicability portion.
Yes

Yes
No
No
The frequency is acceptable but the voltage band is confusing. The generator operating range is +/-5% from rated at full load. Luminant recommends that the voltage excursion be referenced to generator rated voltage.
No
Recommended that in the Footnote and in R1 indicate generator protective relaying.
No
Note: This appears to be dealing with R5 and not R4. R5 Because of the requirement under R5.3 (identification for basis for estimates of probability of staying on-line, etc), the study would take considerable time to compile. I would recommend that the generator owner be provided 90 calendar days rather that the suggested 30 to submit the results. R5.1 It appears that a frequency and voltage excursion must occur at the same time with the estimated time duration that the unit will remain connected. Was it intended that the “and” be an “or”? Would LVRT dovetail into relay loadability for stressed conditions for low voltage conditions between 45 and 90%? (Generator relay loadability is evaluated at 85% (PRC-023-2).) R5.3 Luminant recommends removing this requirement.
No
Generating units placed in service prior to this standard normally have 30+ years lifespan. During the life span, components targeted for LVRT will experience loss of life (time in use, number of operations, environment, etc) which could result in a failure of an LVRT event at the point of interconnection. Because a study may not be able to locate every component, an increase in reliability or the ability of the plant to ride through a low voltage condition could never be guaranteed above its current level. The same issue exist for new units. If the plant was designed to maintain LVRT conditions, there is no guarantee that the plant's ability to ride through low voltage conditions can be maintained during its life span.
No
The LVRT chart should only be limited by values pertaining to a system fault condition as a result of primary and backup transmission line relaying trip times (usually 0-30 cycles)
Yes
Luminant still believes that the standard should be directed to generator protective relaying only.
Individual
Patrick Farrell
Southern California Edison Company
No
Yes
Yes
Yes
SCE believes that the Section 4.2.4 of the Applicability Section should be revised to read "Any technically justified unit requested by the Transmission Planner." We believe that the Transmission Planner is the appropriate functional entity for this role. In addition, SCE believes that Requirement 1 should be revised to allow the Transmission Planner a full 60 days in which to provide the information to the Generator Owner. At various times, Transmission Planners may be inundated with such requests from Generator Owners and may require the extra time in which to respond.

Individual
Kirit Shah
Ameren
No
Yes
Yes
Agree that there are relatively few synchronous condensers installed on the system. Including these devices with other dynamic reactive devices such as SVC's and STATCOMs, rather than in this standard, appears to be a good approach.
Yes
Our comments/concerns are : 1)The wording for Requirement 2.1.4 should be changed to read "Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator". Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment. 2)In Requirement R5, the term "technically justified request" needs to be clarified. 3)In Requirement R2.1.3, it should be clarified that "rotational inertia" should include all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself. 4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included. 5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators. 6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy. 7)The draft uses the term "Point of Interconnection" in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition. 8)Footnote 6 should be a set of sub-requirements for R4. 9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard. 10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote – it's too important in determining which generators must comply.
No
Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary.
Yes
No
Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable
No
Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine with any reasonable accuracy where auxiliary motors would stall and trip off, or contactors drop out.
No
This 90% and 110% ride through times should be longer to handle contingency periods of high voltage during light load conditions or periods where large VAr resources are lost during peak loads. Per our Transmission Planning department high voltages of 110% have been experienced for up to 8hrs.
Yes

1)Comments: Requirement R1.5 is unclear. Are the relays not allowed to trip regardless of frequency if the rate of change is less than 2.5 Hz/sec. If so, the existing generator relays don't have the capability to block for this condition. It would seem undesirable to block for this condition and risk damage to generation. 2)R2.1.3 needs to be more specific. With multiple outlet lines, generators may only be tripped for certain lines or breaker failure conditions. Generators would only be allowed to trip in the "no trip zone" for the specific conditions of the SPS or RAS schemes? 3)R6.2 why are smaller generators allowed to trip 10% of their units? Is this fair to large generators? 4)Do all the requirements of PRC-024-1 apply to all the auxiliary systems, or just the generating unit protection systems? This needs to be made clear for compliance. If applying to all auxiliary systems, guidance will need to be provided on how to meet these standards. 5)For R2 and R6, if clearing a transmission line outlet end of line fault with zone-2 timing exceeds the requirements of Attachment #2, which should be designed for. Does transmission line relays need to be designed to provide performance of Attachment #2 for newly installed facilities?
Group
Southern Company
Antonio Grayson
No
Yes
Yes
It is possible that the owners of the transmission system dynamic reactive devices (such as synchronous condensers, SVCs, STATCOMs, etc) may not be a NERC registered entity at all. Moreover, it is highly inappropriate to just add equipment not mentioned in the original SAR to the standard. It makes more sense, as SDT suggested, to have a separate SAR to address those transmission system dynamic reactive devices.
Yes
1) We question how field tests can be performed on aggregation based facilities. We recommend removing the requirement for developing models for the aggregation of units < 20 MVA for conventional units. 2) Isn't R2.1.3 already required of the GO in MOD-012 (dynamic data on generators) 3) The timing of R5 requirement (90 days) seems to contradict with the schedule for modeling in Attachment 1 (1 1/2 years) for PC initiated model reviews. 4) The background section indicates that the PC can request a unit not in the applicability scope (page 2, last paragraph), but R5 doesn’t say this. The wording on R5 indicates that the PC can request a review of an existing model. 5) Attachment 1 is difficult to use. Please cross reference the requirement that goes with each row of the periodicity table Attachment 1. Please add row numbers to the table. Please use column 1 to briefly label the conditions that controls the applibility of the row (for example - the row including the exceptions could be labeled SISTER UNITS) 6) It is suggested to review the order in which the requirements are currently numbered. The current R3 seems to be out of place (should occur after the requirement that is currently R6). This will more closely match the flow of how the process will work. 7) VSL for R1 needs work – the requirement specifies 30 days – the VSL doesn’t count it tardy until 90 days. 8) The Sister concept needs to be mentioned in the applicability section 9) The exception rule in Attachment 1 should include Sister units at different geographic sites in addition to those at the same site. 10) The exception rule in Attachment 1 should not be limited to 350MVA – if units are identical, then the sister concept should apply. 11) The first bullet of R1 needs to make "model" plural ("models") for the grammer to be correct. 12) As the requirement of R4 is not a response to a request, we suggest changing the wording of the text in M4 from "show that it provided a written response (…) submitted within 180" to "show that it submitted communication (…) within 180", where (…) is shown to indicate no change to the parenthetical element. 13) As requirement R6 is an evaluation of the verified model by the TP, we suggest changing the wording of the text in R6 from "show that it provided a written response" to "show that it provided an evaulation of the submitted model".
Yes
Yes

1) The footnote is clear, however, the exact meaning of the phrase "non-protective system equipment" limitation in R1 and R2 is not clear. Does this exclude any equipment limitation that is protected by a protective relay? Does this allow tripping using protective relays that are protecting a turbine from underfrequency conditions or a generator or transformer from excessive volts-per-hertz conditions? We feel that a fundamental tenant of reliability includes adequately protecting generating plant equipment from detrimental conditions - a generator owner needs to be allowed to protect its equipment from possible damaging consequences of off-nominal voltage and frequency. 2) We believe examples of “non-protection system equipment” include, but are 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. 3) Nuclear stations have an approved Setpoint Methodology which governs the process of determining and documenting setpoints for the equipment at that station. This methodology will incorporate some margin between the expected operating condition and setpoint actuation to help ensure proper operation of the unit but provide the necessary protection as well. How was this considered in the development of this standard?
No
1) This Question is for R5, not R4. 2) We disagree with this approach due to the uncertainty about how to estimate the performance. The detailed dynamic analysis required to make an estimate of a specific units performance is not reasonable to require. The voltage excursion profile needed for an evaluation is that voltage present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. The protective relays and control equipment susceptible to high/low voltage excursions are located on the low voltage side of the generator step up transformer. Does agreeing with the approach mean the philosophical desire to provide the TP with information or mean agreement with the requirement to provide estimations of the voltage excursion ride-through ability? We agree with the philosophical mantra, but we are not sure if a conclusive determination of a unit ride-through capability is possible. Generation Owners need a curve from Transmission that is referenced to the lowside since that is where the relays/equipment are located. 3) Does “estimate of that unit’s performance” only include the estimated time duration of 5.1 and probability of remaining connected in 5.2? Or, does it also include things like the estimated generator terminal voltage, MW, MVars, etc. for the duration of the frequency or voltage excursion? This needs to be clear. 4) The 30 days requirement is much too short. There are a large number of systems and components that would first have to be identified as susceptible to responding to these extreme conditions (especially the voltage conditions). Each of these would then require evaluation, including dynamic analysis for systems and components that respond dynamically over these relatively long time periods. This amounts to major study work on a single unit, much less over many units of many different system configurations and designs having equipment of many different manufacturers and vintages. Also, dynamic studies require accurate system and equipment models to produce valid results and the effort to establish accurate models is no simple task.
No
1) This question is for R6, not R5. 2) We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers. 3) Even if this can be achieved, it will require significant changes in the power plant industry. This will include major changes to plant system and equipment design standards (both U.S. and International). This alone will take years to accomplish. Then, manufacturers will have to design, build, and test plant systems and equipment to meet the new requirements. It is impractical to expect a new plant that can meet both the frequency and voltage requirements to be built in less than 10 years after R6 is imposed.
No
1) The 600 seconds for +/- 10% voltage excursion is excessive. GE has published recommended generator permissible V/Hz settings for a stairstep protective solutions of not allowing > 118% V/Hz to exist longer than 2 seconds, and not allowing > 110% V/Hz to exist longer than 45 seconds. The HVRT curve requires allowing 110% V/Hz for 10 minutes, which is much longer. 2) Generators need a generator side excursion curve to even see if this is feasible. 3) We believe a detailed study needs to

be conducted by the industry for typical power plant designs to help determine the feasibility of power plants being able to ride through these extreme voltage conditions. We believe this study will demonstrate that this will not be possible without major re-design of power plant systems and components.
Yes
1) It is recommended to rephrase R4 so that the requirement (shall statement) is first and the conditions (within x of receiving a request) is second as follows: "The Generator Owner shall provide a written response within 90 calendar days of receipt of a written inquiry from the RC, PC, TOP, or TP regarding an equipment limitation identified in accordance with Requirement R3." More response time than 90 days is needed for cases were a written inquiry is given to a GO (with a very large number of units) for all units in one request. 2) We believe that the condition specified in R6.2 should be limited to PV plants and wind farms? 3) Since Requirement R6 provides exceptions to the requirement (6.3 thru 6.7) these exceptions need to be mentioned in Measure M6. (add "unless one of the exceptions 6.3-6.7 apply" to the end of the sentence.) 4) Employing new 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 (NPLRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements 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 new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant’s licensing and design basis. It is fundamental that the safety of nuclear power plants take precedence. 5) R3 states “each” non-protection system equipment limitation where R1 and R2 say “a”. Is there a reason for this difference? The feasibility of fully analyzing an existing plant to determine this is extremely questionable. There is no doubt that the cost would be horrendous. 6) We suggest modifying Footnote 2 - add “being built to a completed certified standard design” to this list. If the industry is going to move forward in utilizing standard plant designs to reduce cost and expedite getting plants built, the certified design must be acknowledged. If the equipment to meet this standard can be obtained, which is doubtful, the only way to reasonably attempt to have a design that meets it is to start with these requirements as design criteria at the very beginning. To place requirements such as this on completed standard designs would destroy the use of that concept. 7) The approval of this standard as written will have extreme effects on the construction and operation of generating units which could also affect safety and availability. It would greatly increase the cost and schedule for building generation units and impose a huge cost on existing ones. We believe those developing this reliability standard should be sensitive to such concerns and give them consideration. Has this been done? Is it fully documented and available for review by the industry impacted by the proposal?
Individual
Thad Ness
American Electric Power
No
Yes
AEP is not aware of any omissions from the prior draft due to the re-formatting of the standard.
Yes
Yes
Standard models may not be available for wind units and wind facilities (which appear to be within scope), particularly aggregate reactive and frequency response controls at the farm level. As a result, it might be difficult to obtain and provide such information.

Yes
Where these definitions appear to be referenced in the standard (R5 and R6), they seem to be at odds with Attachments 1 and 2. Either the attachments should be used and remove the definitions, or instead, the definitions should be used and remove the references to the attachments in R5.1 and R5.2 and R6. We recommend removing the definition of "Frequency Excursion" and retaining Attachment 1 subject to our comments given elsewhere in this document. We recommend keeping the "Voltage Excursion" definition and eliminating Attachment 2 based on our comments elsewhere in our response.
Yes
Although the footnote is worded somewhat awkwardly, it is clear that a Generator Owner is not required to have protective relaying installed or set for these functions. Suggest using "Generator Owners are not required to have… installed or activated on their units".
Yes
A Generator Owner should only be required to report known limitations that might cause their unit to trip. As written, one could be in violation of the standard for some unknown limitation which might exist and that might only be known after an event has occurred. This question seems unrelated to R4 which states the time provided to respond to a written request for information. Rather, it seems to be related instead to R3 or R5.
No
This question references R5, but we believe the team intended to reference R6. The requirement for new units and plants to not trip within the envelope of Attachment 1 is reasonable; the design of turbines involves some off-nominal frequency versus accumulated time criteria and Attachment 1 is being proposed in view of existing design criteria of major manufacturers. While the Standards team has proposed this in view of OEM design criteria, it would be beneficial to obtain input from the OEMs to learn what issues if any they have with this proposal and what changes and/or incremental costs could be incurred to meet the Standard for new or existing generators. The design and ability of auxiliary systems to meet the requirements outlined in Attachment 1 will require review. To not trip within the envelope of the Attachment 2 Voltage Ride-through Time Duration Curves is another matter. No requirement such as this has ever been imposed on generating units in the past and we question the need for it 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 disturbances occurred on the transmission system. The Attachment 2 VRT curve may thus be an appropriate requirement for wind turbine generators. The applicability to conventional generation, however, is questionable. Further, the curve and the supplemental tables (curve data points) seem to be at odds with the language of R2, e.g. R2.1.1 which states for three-phase transmission system zone 1 faults with Normal Clearing, interpreted to mean as little as 3 cycles up to and not to exceed 9 cycles depending on the transmission relay practice and transmission voltage application. Specific comments on and objections to R6-Attachment 2 are as follows: (1) It is not at all clear that a conventional generating unit could maintain synchronism during POI voltage events within the envelope of Attachment 2. The standard needs to explicitly state that Attachment 2 is not a requirement to maintain synchronism (which is already covered by TPL standards). This point must be made clear within either the text of the requirement or else in a footnote, not just the comment form. (2) Should the SDT retain this requirement, it would be advisable to limit the scope of Attachment 2 in R6 to generator over- and under-voltage relay settings and any unit auxiliary equipment over- and under-voltage protection whose operation could lead to the loss of the unit. However, it is also not at all clear whether auxiliary systems could be designed to withstand voltage disturbances within the envelope of Attachment 2. Further complicating auxiliary systems ride-through, while such a graph may be appropriate for wind farms, it is not appropriate for conventional synchronous generators that 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 insulated to some extent from what may happen on the transmission system. A more appropriate requirement for conventional generation would be to require an automatic over-excitation limiting (OEL) function that is coordinated with over-excitation protection. However, we believe OELs are now standard equipment among excitation equipment suppliers and should not need to be required in a standard. (3) It would be impractical, if not impossible, to test or otherwise verify generator ride-through for POI voltage disturbances within the envelope of Attachment 2. In view of the above considerations, and in the interest of treating all generation types

equitably, we believe a more appropriate approach to generator voltage ride-through would be deference to TPL standards for the types of transmission system disturbances where stability needs to be maintained. This has always been an acceptable criterion for conventional generation ride-through in the past. It is not stated in these terms in this proposed standard and independent review of a random sample of units could demonstrate the units may not meet this R6-Attachment 2 performance requirement though they would meet R2.1.1 and TPL standard requirements. It would be beneficial to state somewhere that any fault or other disturbance on the transmission system for which a conventional generator is expected to survive, a wind farm must also survive without tripping. (A statement such as that may be out of place in this standard and perhaps ought rather to have been included in the new TPL-001-1.) The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied. Therefore, for the purposes of the R6 performance requirement, we believe that reference to Attachment 2 should be removed.
No
We agree that a new generating unit reasonably could be required to ride-though 90 percent or 110 percent voltage at the point of interconnection for 600 seconds at nominal frequency. However, this does not take away from the concerns expressed in response to Q4.
Yes
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. We believe that R2.1.4 must not allow relay settings to trip a generator within the no-trip zone for other system events that would not disconnect the generator. The phrase "generating plant or Facility" is used in R2, R3, R5 and R6, but not R1.
Individual
Larry Grimm
Texas Reliability Entity
Yes
(1) The implementation period in this standard is far too long. It is unreasonable to allow 11 years for a GO to provide a verified model for 50% of its generation capacity. All generation should comply with Requirement 2 within 3-5 years. (2) The periods allowed for providing correction of identified model deficiencies and updates for system changes are too long. It appears (from Attachment 1) that a GO has almost 2 years to provide a corrected verified model after a request from a TP or an equipment change (per Requirements R3, R4 and R5). This work should be completed within one year to ensure accurate system modeling. (3) It is unclear exactly what is required by Attachment 1, and how the material in the attachment relates to the Requirements. The Attachment appears to contain additional requirements. We suggest moving the required actions described in Attachment 1 into the applicable Requirements, such as the requirements and time periods for recording responses and providing new information to the TP. (4) It is unclear what the 10 and 11 year periods/cycles referenced in the first two rows of Attachment 1 refer to. This needs to be clearly explained somewhere. (5) It is our understanding that this standard is intended to require re-verification of models at least every 10 years, but there is no requirement that clearly sets forth any re-verification requirement or period. (6) Requirement 6 requires the TP to determine if a model is “usable” based only on whether the model is functional, omitting any consideration of whether the model is reasonably accurate. An incorrect model could satisfy 6.1, 6.2 and 6.3. We suggest adding an R6.4 relating to whether the model is reasonably accurate, i.e., whether it reflects actual unit performance. (7) In 4.2.3, in the first bullet, “with rating greater than” should be changed to “at greater than,” which is clearer and consistent with the parallel descriptions in neighboring sections. (8) In the “Consideration for Early Compliance” section, first bullet, “applicable regional entity policies” should be changed to “applicable region policies.” In our region, and perhaps others, there are applicable policies, but they are not “regional entity policies.” (9) Several very informal terms are used that should be replaced with more specific language, such as “walk down” (R5.2) and “local grid codes” (Attachment 1). In R6.2, the term

“negligible transients” in too indefinite and should be replaced by a more objective measure. (10) The terms “unit,” “plant,” and “facility” are used inconsistently in the draft. (11) M4 refers to a “request” and a “response,” but there is no request/response interchange in the associated Requirement R4.
Yes
In the ERCOT Interconnection (ERCOT) there are well-established generator under-frequency relay settings (ERCOT Nodal Operating Guides 2.6.2) that are more stringent than those proposed in this standard. ERCOT also has existing low/high-voltage ride-through requirements (ERCOT Nodal Operating Guides 2.9(2)) that are less stringent than those proposed in the standard. We would prefer to include the existing ERCOT parameters in this standard to apply within the ERCOT Region, rather than having different ERCOT and NERC requirements. We suggest that the drafting team consider adding ERCOT-specific parameters in Attachments 1 and 2, matching the existing ERCOT Nodal Operating Guide requirements, in addition to the stated parameters for the other interconnections.
Group
Electric Market Policy
Mike Garton
No
Yes
Yes
Dominion suggests: MOD-026 Section 4.2.4 needs to be removed to be consistent with other standards. MOD-026 Section 2.1.1 “match” should be changed to approximate. The model will never exactly match. MOD-026 Section 2.1.6 remove “structure”. MOD-026 R3 bullet 3 “match” should be changed to approximate. The model will never exactly match. MOD-026 Attachment 1 title is missing “M”. MOD-026 Attachment 1 column “Condition” replace eleven and ten with “eleventh” and “tenth”. MOD-026 Section 4: Applicability should spell out testing exceptions.
Yes
No
The question is confusing because of the phrase “set for these functions.” The language in Requirements R1 and R2 as well as footnote 1 suggest that GOs are not required to have the specific relays “installed or activated on its units. If however, the relays are activated then they are required to be “set” pursuant to the standard.
No
Requirement R4 seems to be duplicative of the obligation to notify the same entities under Requirement R3. Perhaps the language in R4 could be clarified to indicate the distinction.
No
This appears to be a design question that presumably the standard drafting team researched and quantified to provide a basis in framing the curves of Attachment 1 and Attachment 2. If this is true, more documentation should be provided to the ballot body.
Yes
Yes
Dominion suggests the following: Section 3 should capitalize “frequency and voltage excursions”, as they are defined terms. Do not understand R3 bullets. How does increasing your units rating by

≥10% change this? Attachment 2 does not match ±5 voltage schedule per the definition of Voltage Excursion. This curve is not possible. R6 grants new generators exceptions. Where are the exceptions for existing generators? This standard only applies to frequency and voltage excursions within the defined limits. The attachments and requirements go outside of this bound placing much more stringent criteria on the operation of the units. These more stringent criteria may not be possible and should be removed from the standard to align with the definition of applicability. The last sentence of the associated Implementation Plan is confusing. Suggest revising to read: “Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.”
Group
Dynamics Review Subcommittee
Joe Spencer - SERC staff
No
Yes
Yes
It is good strategy to include synchronous condensers with other dynamic reactive devices as they all fall under the same category – providing dynamic reactive support.
Yes
R2: The wording for Part 2.1.4 makes it seem that the required model structure and data only applies to the voltage regulator portion of the excitation system. The DRS recommends that R 2.1.4 be reworded to: "Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator." R5: A "technically justified request" needs to be clarified. We suggest using words similar to those used in the slides associated with this project: "A technical justification that demonstrates, through simulation and/or measured response, that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response." R2.1.3 : The DRS recommends a clarification to “rotational inertia.” Please consider the following wording: "Generator (or plant equivalent) model structure and data (such as reactance, time constants, saturation factors, rotational inertia (including all rotating components), or equivalent data)."
No
Exceedance implies that the frequency is greater than desired frequency. Since the intent is to identify frequencies greater or less than a specified amount from the desired frequency, replacing the word “exceedance” with “deviation” and “beyond” with “outside” seems more appropriate.
No
It is unclear how an entity can have protective relaying settings for new units. Since "existing units" covers units under construction as specified in footnote 2, "new" implies planned units and thus the associated relaying would also be "planned" not "existing." It appears the word “new” should be deleted from sentence one of R1 and sentence one of R2.
Yes
We assume this pertains to R5 not R4. 30 days is probably not enough time for a GO to determine a suitable estimate. We recommend 90 days.
Yes
Requirement R6 not R5.
Yes
While we agree, a technical basis for this 600 secs. duration (and each breakpoint) would be helpful.
Yes
Under R5, Severe VSL Requirement 55 should be Requirement 5. R7 refers to generator protection trip settings as "specified" in R1 & R2. Settings are not specified in R1 & R2. We recommend using "referred to" instead of "as specified." “The comments expressed herein represent a consensus of the views of the above named members of the [insert the full name of the group] only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Group

LG&E and KU Energy
Brent Ingebrigtson
Yes
Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. LG&E and KU Energy suggests tha the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.
Yes
No
Comments: LG&E and KU Energy recommends the wording be changed for R1/R2 to “Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following…” Or, change from “Each GO” to “GO’s that have frequency and voltage protection functions activated to trip a new/existing generation unit.”
No
: LG&E and KU Energy agrees with the approach but recommends 60 days. Moreover, this appears to be R5, not R4.
Yes
: This appears to be R6, not R5 and should be achievable for new units.
No
LG&E and KU Energy agrees with the SERC Generation Subcommittee and proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Yes
LG&E and KU Energy would prefer to have 60 calendar days on
Individual
Anthony Jablonski
RFC
Yes
Yes
Yes
Yes
RFC offers the following suggestions regarding the Violation Severity Levels: 1. VSL for R1 – There is a disconnect between the date listed in the VSLs and requirement. The timeframe for the “Lower” VSL starts at 90 calendar days though the requirement states “within 30 calendar days”. Where does an entity fall if they provide instructions 45 calendar days of receiving the request? Based on the current VSLs, they would not even fall under the “Lower” VSL. 2. VSL for R3 – To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R3.” Or conversely remove this language from the “Severe” VSL and replace with “R3”. 3. VSL for R4 – To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R4.” Or conversely remove this language from the “Severe” VSL and replace with “R4”. 4. VSL for R5 - To be consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R5.” Or conversely remove this language from the “Severe” VSL and replace with “R5”. 5. VSLs for R6 - To be

consistent with the language in the “Severe” VSL, add the following words to the end of the “Lower”, “Moderate” and “High” VSLs: “…as specified in Requirement R6.” Or conversely remove this language from the “Severe” VSL and replace with “R6”.
Yes
Yes
Yes
Yes
For R5, Part 5.1 and 5.2 – suggest adding the word “PRC-024” in front of “Attachment 2” in the last line of the respected Parts.
Yes
Yes
For R3, add the word “generating” in front of the word “Facility” to be consistent with other requirements. The followoing are reccomendations related to the Violation Severity Levels: 1. VSL for R1 – a. The VSL should start off with the following language to be consistent with the language within the requirement: “The Generator Owner that has frequency protective relaying activated to trip its new or existing generating unit failed to…” b. Since there are a number of Parts associated with R1, the SDT may want to consider gradating the VSL rather than making it Binary. 2. VSLs for R2 – a. The VSL should start off with the following language to be consistent with the language within the requirement: “Generator Owner that has voltage protective relaying activated to trip its new or existing unit or generating plant or Facility failed to…” b. There is no reference to any of the Part numbers for R2. Suggest adding references to the Parts to the VSL or since there are a number of Parts associated with R2, the SDT may want to consider gradating the VSL rather than making it Binary. 3. VSLs for R3 a. Suggest not using the language “…prevents compliance with Requirement R1 or R2…” since it is not consistent with the language of the requirement. Suggest stating: “… prevents the Generator Owner from meeting the criteria in Requirement R1 or R2…” 4. VSLs for R5 a. Fix the typo in the “Severe” VSL. Change “R55” to “R5” 5. VSLs for R6 a. The first VSL under the “Severe” suggest referencing “Attachment 1” rather than “Requirement 6.” This will make it consistent with the other “Severe” VSL. b. Suggest adding another VSL which references the GO not following the conditions and exceptions in Parts 6.1 through 6.7. As written, there is currently no reference to the Parts.
Group
FirstEnergy
Sam Ciccone
No
Yes
Yes
Yes
FirstEnergy provides the following additional comments and suggestions: 1. Unfortunately as written this standard may require Generator Owners to purchase software to properly analyze voltage excursions to verify their models. This level of expertise historically existed with the TO/TOP, not the Generator. It will be very difficult for the Generators to develop and maintain this expertise for a verification that will only be run once every 10 years. Also, if additional instrumentation is needed to capture this data, nuclear fleets may be challenged to ensure at least 30% of their applicable units will comply with R2 based on refuel outage schedules. 2. Applicability Section 4.2.4 – We do not agree with the Planning Coordinator being able to include additional units. Even though the standard says that the PC would have to show technical justification, it should not be left to their discretion to

add an entity's unit as applicable. A regional entity is the only ultimate authority that can make this decision and the PC should go through its Regional Entity to prove this justification. We suggest removing this section. Furthermore, it states that the technical justification would need to be verified. It is not clear who would make this judgment on the validity of the justification. 3. We are not clear as to what the standard is referring to when it mentions "volt/var control". 4. In requirement 2.1.1, of R2 it states "2.1.1. Documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance." The SDT should specify the magnitude of the voltage excursion referenced in this section. 5. In the SDT notes they make reference to allowance being given for identical (Sister) units but I did not see it anywhere in the standard. Can Generator Owners take credit for Sister units when supplying the model verification? 6. As a general note, the first draft of this standard was reviewed by industry over 2 years ago. It seems like a long time between drafts to expect the industry to review and vote on a standard given that there may be several new personnel in a company that are new to compliance. I would have hoped the team came out with only a comment period at this time. 7. Attachment 1 - General Comment – "M" is missing from title of attachment "OD-026 Attachment. Also. We assume that the mentioned "voltage excursion" is in reference to the proposed definition found in the proposed PRC-024-1. If so, it should be capitalized and added to the front of the standard and balloted with the standard.
Yes
Yes
Although we agree with the requirement, we noticed that the VRF and Time Horizon is missing for R4. We suggest a LOWER VRF and Long-term Planning Time Horizon.
No
Requirement R5 – It may not be feasible for the GO to provide this information in 30 days. We suggest allowing 90 days. Regarding 5.2 and the estimation of the probability, we are not clear as to what is required. The wording is confusing and cannot offer suggestions because we are not sure what the intent is. R5.1 – Some nuclear plants will not be able to run at 95% voltage indefinitely as required as that voltage is lower than each plant's Licensing Basis for degraded grid voltage. We ask that this standard include an exception for nuclear generators that allow them to report what % of grid voltage will force them into a Limiting Condition of Operation if that % voltage is higher than 95%.
Yes
FirstEnergy offers the following additional comments and suggestions: Requirement R3 – It is not clear how this requirement relates to the identified generator equipment limitations. Furthermore we are not clear what "continuous capacity rating" is referring to. We suggest the removal of the second bullet which states "the generator unit continuous capacity rating increases >= 10%". Requirement R3 – This standard does not account for the fact that nuclear plants have equipment other than the generator that potentially will trip the unit at frequencies/ voltages outside of the limits shown in Attachments 1 and 2. Nuclear plant voltage and frequency trip points are set to ensure safety equipment will operated as specified in the plant's License. The standard needs to allow nuclear generators the ability to specify if something other than the generator protective relays dictates where a unit will trip. Under 6.7 (exception) - A unit or generating plant or generating Facility may trip if the protective functions (such as out of step or loss of field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment. Maybe this section should include an exception for Volts/Hertz protection. General - The standard should state whether disturbances that include both frequency and voltage excursions are covered under the standard. For example, our Volts/Hertz protection trips in 45 seconds at 110%. The standard calls for a HVRT of 600 seconds at 110%. This current Volts/Hertz setting would not meet the standard.
Individual
Travis Metcalfe
Tacoma Power

Yes
Yes
No
Yes
Yes
Yes
No
The required voltage and frequency settings should be determined by the interconnecting entities regional off nominal voltage and frequency plans.
No
Group
PacifiCorp
Sandra Shaffer
No
Yes
Yes
Yes
Modeling wind generation without a developed generic model is a concern. If the generic models are not developed once the standard is effective are exceptions going to be made to accommodate this?
No
The definition for Voltage Excursion provided in the most recent draft of PRC-024-1 is closer to the definition of a voltage deviation. The Voltage Excursion definition should be modified to include a time duration component, e.g. “fast transition” of system voltage beyond the continuous operating band of ±5% of scheduled voltage. Otherwise, a very slow voltage transition could be considered a voltage excursion if it exceeded the voltage band, thereby missing the intent of and time frames set forth in Attachment 2. A similar comment is applicable for Frequency Excursion. A transition time duration is key to the definition of both Voltage Excursion and Frequency Excursion due to the significant impact that these parameters can have on a generating facility.
Yes
Yes
(R4 referenced in the question actually should refer to R5 in the standard)
No
There are going to be certain exceptions to new units or facilities being capable of staying on line under the listed circumstances just as there are current exemptions for existing facilities. Exceptions could be related to VFD (variable frequency drive) operation or motor operation at the plants, which would be true of both existing and new generating plants. There is also a possibility of overcurrent trips during these voltage conditions, tripping would not necessarily be limited to voltage or frequency relays. It would be difficult for Generator Owners to answer this question fully without a thorough

study of how the frequency and voltage excursions will impact generation loads. Generation protective relays do not typically base their protection on transmission system voltages at the point of interconnection.
No
In studying PRC-024 Attachment 2, PacifiCorp believes that the “high voltage duration” curve, which defines the upper edge of the no trip envelope by depicting a 1.10 pu voltage between 1 second and 600 seconds, may potentially conflict with the synchronous generator Inverse-Time V/HZ Relay with Fixed-Time Unit setting recommendations contained in IEEE Std C37-102. For example: At 110% V/Hz, the relay will trip in 291.6 seconds (within the PRC-024-1 No Trip Zone). Additionally, at 109% the setting would be at 1166.4 seconds. PacifiCorp requests that the Standards Drafting Team (“SDT”) further evaluate PRC-024 Attachment 2 to determine if an adjustment to the high voltage duration curve could eliminate this potential conflict.
Yes
In addition to the feedback noted above, the NO votes submitted by PacifiCorp are accompanied with the following comments: (1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: • R1.1.5 – PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. • R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. • R3 – This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. • R6 – The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditons within 95% and 105% of rated generator terminal voltage and during the transmission system conditions define in PRC-024 Attachment 2, with the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner’s study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner’s settings or the setting applicable to in PRC-024 Attachment 2. 2.1.3 Tripping a generator via If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping

a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the is acceptable in the “no trip zone” in PRC-024 Attachment 2 is acceptable. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable than setting relays to trip the generator even if operating within the “no trip zone” specified in PRC-024 Attachment 2 is acceptable. (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC’s Off-Nominal Frequency Load Shedding Plan (“WECC Coordinated Plan”), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. (5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. (6) PacifiCorp offers one comment on the Violation Severity Limits (“VSLs”) proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs. (7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a “one-size fits all” standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies.
Group
TVA - GO
David Thompson
No
Yes
Yes
No
No
TVA believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to “... exceedance of system voltage beyond the applicable voltage schedule
Yes
No

The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
No
The proposed bands would need to 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 designs and no concerns were identified. However, it is 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.) have been and are 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 less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
No
TVA proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience.)
Yes
During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: • Important Existing nuclear plant settings are inside the published no-trip bands • How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. • Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No

Applicability to Smaller Units: The proposed standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some local areas. The applicable criterion should be the same as those used in the Compliance Registry. No capacity factor exemptions should be allowed without a technical justification. Also see section 4.2, footnote 2. This is a broad exemption, and as we saw recently during the continent-wide heat wave, almost all units within our control area were operating. The requirement is to test once every 10 years. This is not an excessively onerous requirement.
Yes
The inclusion of all reactive resources as BES Elements covered by a separate standard would be consistent with the current draft of the proposed Bulk Electric System (BES) Definition and Designations being proposed by the BES standard drafting team.
Yes
Requirement R5 – Please define the term “technically justified.” We recommend using wording similar to Comment form paragraph 8) in that definition: “[S]upply technical justification that demonstrates either a) the unit affects a stability limit, or b) the simulated unit response does not match a measured unit response (most likely captured during a system disturbance event).”
No
Requirement 1, paragraph 1.1 requires that units remain connected, 1.1. When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive. Yet the definitions of Frequency and Voltage Excursion could be misinterpreted to apply only to trips occurring when the frequency or voltage at the time of trip-out was outside the normal operating range. We do not believe that it was the intent of the drafting team to exempt units which might trip within the normal operating range during an event. Therefore, we propose to change the focus from Excursions outside a normal operating range to variations within and outside that normal operating range, out to specified limits (the operating envelope). We suggest that the term Frequency and Voltage Excursion be re-defined as variations follows: Frequency [delete “Excursion” add “Variation”] – an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] frequency within a planned continuous operating band, e.g., 60±0.5 Hertz, and beyond a planned continuous operating band to specified limits (Attachment 1). Voltage [delete “Excursion” add “Variation”] – an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] voltage within a planned continuous operating band, e.g., 0.95 to 1.00 per unit, and beyond a planned continuous operating band to specified limits (Attachment 2). This definition includes certain types of specified variations: (a) Operation within an allowable normal operating bands, such as voltage variations within an allowed ±5% of scheduled voltage, e.g. from 0.95 to 1.00 per unit. (b) Operation within a modified scheduled operating band voltage change, such as with the range around a scheduled nominal voltage reduction during a brown-out, where the allowed voltage operating band is intentionally reduced, and (c) Operation up to limits specified and/or referenced in MOD-026. For example, voltage variations either within or outside of the scheduled operating band of 0.95 to 1.05 per unit of nominal, e.g., a 328–362 kV operating band around a 345 kV scheduled nominal voltage. We propose to change the Purpose wording (and similar wording elsewhere) as follows: Purpose: Ensure generating units remain connected during frequency and voltage [delete “excursions” and add “variations”] and ensure expected generating unit performance during frequency and voltage [delete “excursions” and add “variations”] is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.
Yes
Yes
Yes
Yes

Yes
Requirement R3. – Delete the word “expires” and replace it with the words “documentation should be renewed” The underlying technical justification for this standard should be supported by a white paper similar to the document available at this link (AREVA PRC-24 White Paper Clean.doc): http://xa.yimg.com/kq/groups/28536519/188315025/name/AREVA%20PRC-24%20White%20Paper%20Clean.doc Requirement R3, bullet 1 allows for an exemption for existing plants subject to equipment failures until “the limitation [limiting equipment] is repaired or replaced.” Similar temporary exemption language should be incorporated in R6 for new units that experience equipment failure-related limitations. The drafting team may also wish to address a requirement for repair or replacement timeliness in both R3 and R6.
Group
Santee Cooper
Terry L. Blackwell
No
We’re not sure these definitions serve a useful purpose, since, later on in the standard, these excursions are defined by the curves in the attachments.
No
The sub-requirements of R2 could be read as prescribing exactly where you have to set this relaying. Often our relay set points originate with the OEM and are based on protecting the Generator and Turbine. The finalized curves that originate here should be used as a means to arrive at those settings, but, as long as the settings do not cause the relaying to operate for the ranges in the finalized curves, the requirements should be satisfied (It shouldn’t have to be stated that you can set them less stringent, if you can not have the relaying entirely).
No
It should be ascertained how and if the TP will use this in TPL-001 analysis. It will be unclear how to demonstrate compliance.
No
This appears to refer to R6. 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 guidence 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 utilzed at power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.

No
The LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
No
Individual
Gary Chmiel
GE Energy
No
Yes
GE has no comment.
Yes
GE has no comment
No
GE has no comment for MOD-026
Yes
GE has no comment
Yes
GE has no comment
Yes
GE has no comment
Yes
The requirement is achievable in concept, however, there is a serious omission in the definition of the requirement. It is not clear how the magnitude of the three phase voltage is defined, for example: average of the individual phase magnitudes, magnitude of the least phase, positive sequence. Also, it should be clearly defined whether the requirement applies to the rms, 60 Hz component, or peak magnitude of the voltage.
Yes
GE has no comment
Yes
Clause 6.1.1 allows an exception from meeting the ride through requirements for voltage support equipment that is not in service. Often such equipment is installed solely for the purpose of acheiving ride through. It is not clear that there are any NERC standards requiring that this equipment be maintained to have a minimum level of availability. As worded, this clause could create a means by which a GO could indefinitely avoid requirements, and subsequent penalties for non-compliance.
Group
Public Service Enterprise Group
John Seelke
No
No
If the SDT were to prepare a table showing how the requirements in the prior version were incorporated into the present version and included that in its background information on the standard, this question would be answered.
Yes
The team needs to develop a consistent rationale on synchronous condensers in all of the standards being addressed in Project 2007-09. The team should consider asking the NERC Planning Committee to develop a white paper on the need (or lack of need) for synchronous condenser data.
Yes

1. The capacity factor calculation referenced in 4.2 should refer to a future attachment that the team would develop that explains (a) which reliability standard one would use to for a unit's capacity rating (such as MOD-010) for the calculation and (b) a sample calculation. 2. In 4.2.4, the sentence "Any technically justified unit requested by the Planning Coordinator" should specify (a) the entities that may develop the technical justification, (b) the entity who will evaluate that technical justification and (c) the criteria for judging whether an excluded unit should be included. 3. In R1, first bullet: a. Would the instructions issued by the Transmission Planner on "on how to obtain the list of acceptable excitation control system and plant volt/var control function model for use in dynamic simulation" cover "acceptable" verification via staged tests and "acceptable" verification by a measured system disturbance per R2.1.1. b. Are Transmission Planners the appropriate entity to determine "acceptability" of models or verification since there are about 120 Transmission Planners registered in the Eastern Interconnection? See the comment below regarding R2.1.1 4. R2.1.1 addresses verification via either staged tests or a measured system disturbance. However, the standard leaves the judgment of the acceptability of verification performed by a GO to the Transmission Planner. We suggest that the team include an attachment to the standard that provides guidance for how to perform acceptable verification, covering both staged testing and a measured system disturbance. 5. R5 is unclear. For example, does the 90-day submission period in 5.1 address submissions under 5.2 and 5.3, or does it require that the GO merely acknowledge receipt of the request within 90 days? Since 5.2 addresses plans to verify a model, why would "corrected" data in 5.3 be due within 90 days? 6. Both R3 and R5 require GO action in response to a notification by a Transmission Planner (R3) or a Planning Coordinator (R5). Can a Transmission Planner or Planning Coordinator require a response from a GO for generators that are not yet verified by the GO per the timetable in section 5? If not, it appears that R3 and R5 should be rewritten to recognize this limitation. 7. The July 29 webinar made clear that generator exciter model verification applies to synchronous generators and the plant volt/var control function applies to non-synchronous generators. It would be helpful if this clarification was made in the standard itself, perhaps in the purpose statement.
Yes
Yes
A one-sentence statement should be added stating that the protective relays affected by this standard are only the generator protective relays, not any other relays for the unit and/or facility.
Yes
Yes
No
Typical OEM recommended protective relay settings for generator UV are significantly more stringent than that which is outlined in Attachment 2 of the draft standard. Intuitively, it would seem that a generator and its auxiliary connect loads having the requirements to ride out 0.7 pu voltage for a period of 2 seconds is unrealistic.
Yes
a. Per the July 29 webinar discussion, R2.1.1 needs to be rewritten for clarity. b. The "exception" process in R3 and R4 is too vague as to "who" decides whether this standard applies to a generator. If a GO describes the limitations per R3 and one of the four entities listed in R4 inquires about a specific limitation, and the GO subsequently replies to that entity, is the exception confirmed? Under what circumstances a description of limitations by a GO in R3 would be challenged? Unless the exemption to this standard is made clear, the result will be confusion when the standard is approved.
Individual
Barry J Skoras
PPL Electric Utilities
No

The expression, "Units or plants" in para. 4.2 should be changed to "units" to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at ~0.1% CF does not need to test the diesel. Also, eliminate the word "to" in the expression in para. 4.2.1, "For each plant with a gross aggregate nameplate rating greater than to 100 MVA"
Yes
Yes
Yes
1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements. 2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word "software;" and para. R2.1.1 should state that "Verification consists of developing one or more models that collectively include the following information:" The present R2.1.1 text, "acceptable to the Transmission Planner," is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO's first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified status only after being accepted by the Transmission Planner, the term "verified model(s)" in the R2 Violation Severity Levels should be replaced with, "initial submittal of proposed-verified model(s)". 3. 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 para. 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. 4. The definition of a "technically justified request" in para. 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? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.
Yes
1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary. 2. The need for excursions as severe as those of Att.2 should be confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/-1.74%) would be considered abnormal for our system (PJM).
No
Recommend the wording be changed for R1/R2 to " Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following…"
No
1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5. 2. The question above cites "frequency and voltage excursions [emphasis added]," the question 4 below deals with "frequency or voltage excursions," para. R5.1 states "Frequency Excursion…and a Voltage Excursion" and para. R6 references "Frequency Excursion or Voltage Excursion." The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. 3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be

one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. 4. In the event that R5 remains as-is, 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. 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024.
Yes
1. Excursion-estimate requirements for new units are presented in R6, not R5. Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult.
No
Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Yes
1. The term "continuous capacity rating" in the second bull-dot item of R3 should be replaced with "Normal Rating or Emergency Rating," to eliminate ambiguity via use of NERC Glossary-defined terms. 2. The term "non-protection system" in R3 should be replaced with "non-Protection System," to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable). 3. Paras. R5.1 and R5.2 suffer in terms of clarity from consisting of a single sentence that is over 80 words long, with not a single comma or semicolon to guide the reader. NERC standards should make use of normal technical-writing style and punctuation
Group
PPL Supply
Annette Bannon
No
The expression, "Units or plants" in para. 4.2 should be changed to "units" to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at ~0.1% CF does not need to test the diesel. Also, eliminate the word "to" in the expression in para. 4.2.1, "For each plant with a gross aggregate nameplate rating greater than to 100 MVA".
Yes
Yes
Yes
1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements. 2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word "software;" and para. R2.1.1 should state that "Verification consists of developing one or more models that collectively include the following information:" The present R2.1.1 text, "acceptable to the Transmission Planner," is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO's first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified

status only after being accepted by the Transmission Planner, the term “verified model(s)” in the R2 Violation Severity Levels should be replaced with, “initial submittal of proposed-verified model(s)”. 3. 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 para. 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. 4. The definition of a “technically justified request” in para. 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? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified. 5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.
Yes
1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary. 2. The need for excursions as severe as those of Att.2 should be confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/- 1.74%) would be considered abnormal for our system (PJM).
No
1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5. 2. The question above cites “frequency and voltage excursions [emphasis added],” the question 4 below deals with “frequency or voltage excursions,” para. R5.1 states “Frequency Excursion…and a Voltage Excursion” and para. R6 references “Frequency Excursion or Voltage Excursion.” The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. 3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. 4. In the event that R5 remains as-is, 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. 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024.
Yes
1. Excursion-estimate requirements for new units are presented in R6, not R5. Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult.
No
Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Yes
1. The term “continuous capacity rating” in the second bull-dot item of R3 should be replaced with “Normal Rating or Emergency Rating,” to eliminate ambiguity via use of NERC Glossary-defined terms. 2. The term “non-protection system” in R3 should be replaced with “non-Protection System.”

to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable). 3. Paras. R5.1 and R5.2 suffer in terms of clarity. Suggest rewording these paragraphs to make them easier to understand. 4. An exception should be added for nuclear facilities that may not be able to ride through the frequency and voltage excursion outline in PRC-024 with out impact to nuclear safety systems.
Individual
Andrew Z. Pusztai
American Transmission Company
No
Yes
Yes
ATC believes that synchronous condensers may have significant impact in the areas where they are installed. Therefore, ATC agrees that they should be added to the NERC Compliance Registration Criteria and that a separate SAR should be established to develop a separate reliability standard for synchronous condensers and other dynamic reactive devices.
Yes
Please give consideration to the following suggestions: 1. In Applicability, 4.2, Include the explanation that “average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value” since some have asked how this value is defined and calculated. 2. In Applicability, 4.2.4 - add “Transmission Planner” to this item because Transmission Planners may also have insight and the means to provide technical justification for the inclusion of specific units in their system. 3. In Requirements, R1, bullet 1 - remove this bullet 1, or combine it with bullet 2, because it appears to be redundant with bullet 2, rather than distinctly different. 4. In Requirements, R2.1.4 - replace “model structure and data” with “block diagram and model parameters” for more clarity. 5. In Requirements, R2.1.6 - replace “model structure and data” with “manufacturer, model number, block diagram, and model parameters” for more clarity and specificity. 6. In Requirements, R2.1.6 - add ”and indicate whether the power system stabilizer is planned to be in-service and out-of-service in the planning horizon.” 7. In Requirements, R4 – revise the text from “within 180 days of making changes” to “within 180 prior to making changes” for more clarity.
Yes
Yes
Yes
Yes
Yes
Yes
Please give consideration to the following suggestions: 1. In Requirements, R1, R2, & R3 – include a footnote for the references to “non-protection system equipment” that defines or gives a few examples of this equipment to add clarity. 2. In Requirements, R3 – add the requirement that the GO provides the expected duration of the limitation, if it is known. 3. In Requirements, R5.2 – include a footnote or example of “25% estimated probability increments” to add clarity. 4. In References – include references that provide more technical justification and background for the voltage and frequency limits given in Attachment 1 and Attachment 2. 5. In Attachment 1 - add a “Return to between 59.5 Hz and 60.5 Hz frequency” text box to be consistent with the labeling in Attachment 2. 6. In Attachment 1 – add the title “Curve Data Points” to the Frequency/Time table to be consistent with Attachment 2. 7. In Attachment 2 – modify HVRT and LVRT tables (perhaps combine them into

one more compact table) to be consistent with the table in Attachment 1 and fit on the same page. 8. In Attachment 2, 5a - expand to “Power factor is 0.95 lagging (i.e. supplying reactive power to the system as measured at the generator terminal)” to be more definitive.
Group
Florida Municipal Power Agency
Frank Gaffney
Yes
FMPA appreciates the efforts of the SDT to “right-size” the applicability to plants that truly impact the stability response of the system. However, the words used in the draft standard allow a loop-hole to the SDT’s intent. Footnote 4 to the Applicability section states: “(a) technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response”. If a region wishes to include 1 MW generators in the process, all they have to do is show that the unit’s actual response does not match the simulated response without a technical justification to show that the 1MW generator has any impact on the actual stability response of the system. The SDT should change the “or” in footnote 4 to “and” meaning that the technical justification needs to include both an impact to a stability limit AND a difference between actual and simulated response. In addition, for R5 and footnote 4, who judges what is and what is not a “technical justification”? For instance, NPCC in their regional UFLS standard proposed to cause 1 MW generators to register and be included in the standards. Does the region have the final say on technical justification? The staged test in R2.1.2 and Attachment 1 that is required if an actual event does not occur is onerous. FMPA believes this “staged test” is impractical and should be eliminated. Within a ten year period, an actual event is likely to occur resulting in a recorded response. If an actual event does not occur, then, the risk of inaccuracy is small and a “staged test” with associated higher risk should not be required to only marginally improve accuracy.
Yes
No
The term “protective relaying” is confusing in two ways: 1) the footnote is ambiguous as to how it applies; and 2) it calls into question whether this is a “generation Protection System” applicable to PRC-004 and PRC-005 (especially when considering the inconsistent use of “non-protection system equipment” in R3). FMPA suggests the term “safeguard” instead of “protection”, e.g., a “frequency safeguard system” to avoid this ambiguity and with a footnote to make more clear that systems like GE Mark VI’s are or are not included. Similarly in R2, it is unclear what “voltage protective relaying” is. FMPA suggests using the word “safeguard” instead of “protection”. Also, it is unclear whether station service voltage safeguards are included, such as motor contactors. In addition, “external to the plant” as used in several requirements (e.g., R1, R2 and R6) is ambiguous. We assume that this would also mean beyond any radial connection (e.g., generator lead) to the plant and would suggest changing the term to something like: "caused by an event beyond the point at which the plant is radially connected to the transmission system".
No
R4 is missing the VRF and Time Horizon. FMPA recommends “Lower” and “Long-term Planning”.
No
First, FMPA believes the SDT is referring to R6 not R5. Technically, the requirement is inconsistent with the question. The requirement is to design, build and maintain to prevent tripping, it does not say “thou shall not trip”. If a generator is designed, built and maintained to specifications that should not trip, but, a generator trips anyway in a real-life event, is that a violation?
Yes
The bullets in R3 are onerous. The bullets would essentially eliminate the ability to replace like-with-like which would have an impact on spare equipment strategy and stores since existing spares in the

warehouse could not be used. If spares were not available that could meet the new criteria, the GO would be forced to either keep a unit off-line or be non-compliant. FMPA suggests eliminating the bullet, or at most, institute something like a Cyber Security Technical Feasibility Exception (TFE) process. In addition, in the bullets at the end of R3, is the 10% incremental or cumulative over time? E.g., if a GO does a capacity augmentation of 5% one year and then another 5% increase 3 years later, does that trigger the 10%? R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" between minimum and maximum output of the generator implied?
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
Mostly, HQT's frequency and voltage curves are more stringent for generators, as the area for no trip zone is wider. However, the following points on those curves of attachment 1 and attachment 2 are too stringent and we ask to consider these modifications: • On the frequency curve, for wind or thermal generation only, the no trip zone between 0 and 5 seconds should be limited to an over frequency of 61,7 hz. • On the voltage curve, the no trip zone should be restricted as follow: ♣ Between 1 and 2 seconds, to 0,75 pu, ♣ Between 2 and 3 seconds, to 0,85 pu.
Yes
Yes
The graph of voltage from the interconnexion of Quebec was reflected from the FERC order 661-A which is different from the graph from this standard. Please justify the source of the present standard.
Individual
Scott Berry
Indiana Municipal Power Agency
No comment
no comment
no comment
Yes
IMPA appreciates the efforts of the SDT on getting the applicability section correct for the plants or units that truly impact the stability response of the BES. However, the standard does contain a loop-hole to the SDT's intent. On page 3 of 16, footnote 4 to the applicabilty section (4.2.4)states: "a technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response". The first or word in that sentence should be replace with the word "and". A technical justification for verifying each of those units and plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit should both be required. By requiring both of these items, it might prevent units the size of 1MW from having to perform this standard. In addition, who qualifies what is a technically justified unit or what is a technical justification? Past history as shown that technicaly justifications have been used "losely" by different regions and entities. The Generator Owner should have some means of appealing this request by the Planning Coordinator.
no comment
No

The term "protective relaying" is confusing in a two ways: 1) The footnote needs to clarify how it applies; and 2)the term calls into question whether this is a "generation Protection System" applicable to PRC-004 and PRC-005. It needs to be made more clear that systems like the GE Mark IV and VI control systems are or are not included. R2 is also not clear when using "voltage protective relaying". It is not clear if voltage safeguards on motor contactors are included. The standard also needs to make more clear what "external to the plant" exactly means.
No
This is actually requirement R5. IMPA does not see any value in assigning a standard requirement to a Generator Owner that is just an estimation of performance when it might be a far off estimation of performance compared against actual performance of an existing unit or generating plant. This standard should concentrate on the setting of relays and not have Generator Owners estimate how their unit or generating plant will perform during a Frequency/Voltage Excursion. This standard should also not force Generator Owners to perform studies or model their unit or generating plant since they are not guaranteed or reliable either.
No
This is actually requirement R6. IMPA does not believe this technology is currently achievable for new units or generating plant/facilities on all generation producing fronts. The technology should be in place and proven on all generation fronts before such writing of standard requirements.
no comment
no comment
Individual
Armin Klusman
CenterPoint Energy
No
(a) CenterPoint Energy agrees with the time duration value of the 0.9 pu voltage level up to 600 seconds and believes this will coordinate with existing undervoltage load shedding systems (UVLS). However, CenterPoint Energy believes there are numerous relays presently set at 2.0 seconds and 3.0 seconds to shed load in a voltage excursion and, therefore, there is not a sufficient margin for coordination at the two second and three second low voltage points in Attachment 2. CenterPoint Energy recommends these two points in Attachment 2 be revised to 2.5 and 3.5 seconds. That is, the data points (Time / Voltage) in the LVRT DURATION table would be as follows: 0.15 / 0.000, 0.30 / 0.450, 2.50 / 0.650, 3.50 / 0.750, and 600 / 0.900. (b) In addition, CenterPoint Energy believes there is insufficient margin at 1.0 seconds for high voltage ride through due to voltage over-shoot following a zone 1 fault. To provide an adequate margin, CenterPoint Energy recommends the 1.0 second high voltage point in Attachment 2 be revised to 1.5 seconds. That is, the data points (Time / Voltage) in the HVRT DURATION table would be as follows: 0.20 / 1.200, 0.50 / 1.175, 1.50 / 1.150, and 600 / 1.100.
Yes
(a) CenterPoint Energy does not agree with limiting the applicability of Requirement 2 to just “voltage protective relaying”. In effect, this would allow possible tripping of generation during off nominal voltage excursions from several other types of relays, such as generator backup over-current and impedance. CenterPoint Energy recommends that this standard be applicable to any generator Protection System relays that operate on voltage and / or current. (b) In Requirement 2.1.1, the fault clearing time should be established at a fixed 9 cycles, instead of site-specific, actual clearing times. R2.1.1 should be written as: “For three-phase transmission zone 1 faults, set generator Protection System relays based on a fault clearing time of 9 cycles”. (c) Requirement 2.1.2 provides for location-

specific criteria that are unnecessary and could have unintended consequences, as such criteria can change over time with additions and modifications of the bulk electric system. CenterPoint Energy believes NERC reliability standards should not include fill-in-the-blank, location-specific criteria and recommends R2.1.2 be deleted.
Group
NERC Staff
Mallory Huggins
No
We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
Yes
No
It is most efficient to address synchronous condensers in the same project as generators given that synchronous condensers have many of the same characteristics as generators. Static var compensators (SVCs) and static compensators (STATCOMs) are sufficiently different from generators and synchronous condensers to be appropriately covered in a separate SAR. Despite the low penetration of synchronous condensers in North America, these devices are most likely installed to extend a dynamic voltage security limit as noted by the drafting team. Due to the importance of these devices, validated models should be required for these devices similar to generators. Reliance on other motivations for equipment owners to validate models is inconsistent with requirements for generators and does not provide appropriate assurance that the equipment owners will validate models necessary for system reliability.
Yes
Validation of the voltage and reactive power response of generating units for significant system disturbances indicates that the dynamics database quality is not as robust as noted in the Background Information posted with this standard. As a result NERC staff offers the following three specific comments for improving the quality of the model database: 1) It is not possible to accurately model system voltage and reactive power response with valid models for only 80 percent of the installed system capacity. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per the SDT estimates this will assure accurate modeling for approximately 95 percent of installed capacity. 2) We disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions when reactive support may be most critical thereby making valid models critical to system reliability during those conditions. While they should not be exempted from the standard, we do believe it may be appropriate to assign these units lower priority in the implementation plan. 3) The initial completion of validation for all applicable units and periodicity for model verification should be 5 years, not 10 years. The 10 year time is excessive. Any Functional Model entity that requires the models, including Planning Coordinators, Transmission Operators, and Reliability Coordinators, should be permitted under Requirement R3 to provide notification to the Generator Owner that the model is not usable or that the predicted response did not match the recorded response to a transmission system event. Also, Requirement R3 should permit entities to notify the Generator Owner that the model is not usable for any reason. We recommend removing the list referencing Requirement R6, parts 6.1 through 6.3, because it is not and cannot be an all-inclusive list of problems that could make the model not usable (e.g., the model could cause the simulation software to “freeze”). In the first row of the Periodicity Table, transmission of the verified model and documentation to the Transmission Planner should occur within 180 days from the date the recorded response is collected similar to all other rows in the table. There is no apparent basis for the additional time provided in the first row of the table. The violation risk factors associated with Requirements R1 through R6 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system. The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R6 should include the operations planning horizon. In

Requirement R6, part 6.2, the reference to negligible transients is not measurable. We recommend modifying this to ". . . results in a response that varies less than the numerical stability of the program used for the simulation." In Requirement R6, part 6.3, the introductory phrase "For an otherwise stable simulation" is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with "A disturbance simulation results in . . ." The SDT should consider use of the word validation instead of verification and assure that the terms used in this standard are consistent with other standards.
No
NERC staff believes it is unnecessary to define these terms to achieve the reliability objective of this standard. We further note that the proposed definitions of these terms are in conflict with usage of the phrases frequency excursion and voltage excursion in other standards and a defined glossary term. A review of existing NERC standards and the NERC glossary identifies the following inconsistencies: (1) Standard BAL-003-0.1b "requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting." Events identified for use in analyzing and setting requirements for frequency response are associated with frequency deviations of less than ±0.5 Hz, and not necessarily deviating from 60 Hz. (2) Standard EOP-004-1 requires reporting for "any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in sustained voltage excursions equal to or greater than ±10%." (3) Standard PRC-006-1, refers to "system frequency excursions below the initializing set points of the UFLS program." The initializing setpoints of UFLS programs vary by region. (4) The defined term, Disturbance Monitoring Equipment, includes "Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions." We also observe inconsistency within the draft PRC-024-1 which refers to "a Frequency Excursion defined by the curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2," which is in conflict with the proposed definitions. Given the range of contexts in which the phrases frequency excursion and voltage excursion are used we believe it is most appropriate that each standard identify the excursions of interest in the context of that standard, rather than establishing defined terms with specific numerical values.
Yes
Yes
Yes
Yes
Yes
The applicability section should be expanded to address both applicable entities and applicable facilities similar to MOD-025-2 and should apply to individual generating units >20 MVA (gross nameplate rating) and generating plants/Facilities >75 MVA (gross aggregate nameplate rating), regardless of interconnection voltage. The percentage of units that must be compliant in Effective Date sections 5.1.1, 5.2.1, and 5.3.1 should be based on an MVA basis similar to other standards in Project 2007-09, such that the phrase "% of its applicable units" is replaced with "% of its applicable units on an MVA basis." The SDT should consider the implications of Requirement R1, part 1.5, which appears to preclude unit tripping when frequency rate-of-change is less than 2.5 Hz/s, even if the frequency is above 62.2 Hz or below 57.8 Hz. The voltage curves in Attachment 2 should be applicable for any operating condition that falls within the voltage-time curves regardless of the initiating event that causes the voltage excursion. As such, Requirement R2, part 2.1.1 should be removed from the standard. Also, we understand from the webinar that the voltage curves in Attachment 2 represent positive sequence voltage. If voltage relays that sense phase-to-ground or phase-to-phase voltage are set according to this curve, generator tripping could occur for normally cleared unbalanced faults (e.g., the unfaulted phase voltage during a single-line-to-ground may exceed 1.2 per unit on an effectively grounded system). The drafting team must develop curves that can be used directly for setting protective relays to assure that generators remain connected for both balanced and unbalanced faults. System conditions may change more quickly than a Transmission

Planner can identify and convey applicable voltage relay setting requirements to a Generator Owner. We are not aware of any reason a Transmission Planner would require less stringent criteria than Attachment 2. For these reasons, the following items should be deleted: (1) Requirement R2, part 2.1.2; (2) The phrase referring to “the voltage profile at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault . . .” in Requirement R5, parts 5.1 and 5.2; (3) Requirement R6, part 6.3; and (4) Note 2 to the Voltage Ride-Through Curve Clarifications. Equipment limitations will not change based on modifications to changes in generating unit capacity. The second sentence in Requirement R3 should be changed from “the equipment limitation expires . . .” to “The waiver for compliance with Requirements R1 and R2 associated with the equipment limitations expires . . .” The conditions in Requirement R6, parts 6.1 and 6.2 could be interpreted to indicate that this requirement only applies to generating plants/Facilities greater than 75 MVA. The standard should be revised to be clear that it also applies to generating units greater than 20 MVA.
Individual
Dan Hansen
GenOn Energy
No
The comment is for R5 for the June 15, 2011 draft. The wording is too open-ended and subjective in scope. Similar to R1 & R2, the requirement should be clearly defined and limited to devices that directly respond to generator voltage or frequency. R3 already requires the information of other control or protective devices. Typically, the Generator Owner does not monitor the interconnection voltage for protection purpose; rather generator terminal voltage is used for generator protection. The modeling is performed by others, but the burden of analysis is being placed upon the Generator Owner to determine performance probability for information not in their possession. 30 days is a short period of time for this analysis when hit cold with a request like this, especially during outage season.
No
Applied to R6 of the June 15, 2011 draft. It does not appear that the SDT has carefully considered the possible impact of Attachment 2 on plant electrical auxiliary motors and contactors. The SDT should ask an power plant engineering company the impact on the electrical auxiliaries of an 800MW coal unit with a scrubber.
No
10 minutes is a long time for some unavoidable configuration of electrical auxiliaries.
Yes
A strong disapproval of the R3 equipment limitation expiration with a generating unit rating increase of 10%. The expiration is unnecessary and is based upon an arbitrary criterion that may be totally unrelated to basis for the limitation. A backwards approach has been taken with the application of Attachment 2, which represents very poor performance of the transmission system for voltage recovery after a fault. This standard will have the affect of permanently defining this as acceptable transmission performance, which should not be the case. This is inequitable since it imposes the lowest common denominator of one segment of the industry and unilaterally transfers the responsibility for that performance upon another seqment (every generating unit on the continent). The Generator Verification team has developed extensive requirement for Generator Owners to provide accurate model data for system studies, but Generator Owners get no benefits in return for their effort and expense. Rather than imposing Attachment 2 on Generator Owners, the more correct way is to require Planning Coordinators, Transmission Operators or Transmission Planners to provide planning study results and voltage recovery profile at the generator terminals (this is where the protection and controls are applied). This will enable Generator Owners correctly apply protection settings as appropriate. Another option is to drive performance improvements on the Transmission

system. Attachment 2 should be set a much higher standard of performance of the transmission system (median or higher), and require the Planning Coordinators, Transmission Operators or Transmission Planners to identify the locations where the higher standard is not attainable and provide the voltage recovery profile.
Group
Bonneville Power Administration
Denise Koehn
No
Yes
Yes
Yes
MOD-026: By making Transmission Planners responsible for generator verification instead of regional entities, it may be more difficult to produce integrated regional models. The standard should also apply to Regional Coordinators to ensure consistent generator verification requirements within regions.
No
R2.1.1 – Please clarify/verify: • That the allowable voltage relay trip time is greater than the normal fault clearing time up to a normal clearing time of 9 cycles; • That tripping is allowed above 9 cycles regardless if it is normal clearing or backup clearing; and, • That for generators in close proximity the normal clearing time is coordinated to ensure it is no greater than what a specific generator was designed to withstand.
No
R3-R4 - Generator Owners may be unwilling to share proprietary information in response to requests from Reliability Coordinators, Planning Coordinators, Transmission Operators, or Transmission Planners, because of manufacturer restrictions or for other reasons. Should the standard anticipate this issue?
R5 - WECC Reliability Subcommittee discussions indicated that protection generation relay performance at the Point of Interconnection was different than if the measurement point is at the low side or high side of the step-up transformer. The NERC Standard should specify the measurement point at the high side of either the generator step up transformer, or at the high side of the collector transformer where multiple small generators are aggregated at a collector substation. Attachment 2 – BPA suggests modifying the diagram to reflect changes to Requirement R2.1.1 above, e.g. to show that allowable voltage relay trip time is greater than the normal fault clearing time if the normal clearing time is less than 9 cycles.
Yes
The proposed standard uses both "zone 1" and "Zone 1", which we assume mean the same thing. What is the source of the Zone 1 determination?