Individual or group. (36 Responses)
Name (19 Responses)
Organization (19 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (2 Responses)
Comments (36 Responses)
Question 1 (32 Responses)
Question 1 Comments (34 Responses)
Question 2 (26 Responses)
Question 2 Comments (34 Responses)
Question 3 (29 Responses)
Question 3 Comments (34 Responses)
Question 4 (29 Responses)
Question 4 Comments (34 Responses)
Question 5 (0 Responses)
Question 5 Comments (34 Responses)

Individual
Jeffrey Streifling
ATCO Power
Yes
The requirement is clear enough -- the ambiguities arise in the attachment.
No
I think you are trying to handle the case where the transmission system voltage becomes depressed to 0.85 pu. This does not cause the voltage at the armature terminals of the generator to change, except in a transient time frame (or if the AVR is in manual or drooped). During the transient time frame, the armature terminal voltage would be depressed to 1-(0.15 * (Xd'/(Xd'+Xt)) pu volts (Xt=transformer reactance (pu), Xd'=transient machine reactance, pu), but this will reduce, not increase, the reactive power output, so the worst case for voltage support is in the steady-state time frame after the AVR corrects the voltage. After the AVR corrects the voltage, the armature terminals will return to approximately 1 pu voltage (or whatever it was set at before the disturbance) and the VAR outflow will be the transformer MVA times 0.15/%IZ (0.15 = 1-0.85 = amount voltage is depressed, %IZ transformer rated impedance). (This is just Ohm's law applied to the voltage difference across the output transformer between 1 pu armature voltage and 0.85 pu system voltage.) There is no reason to require simulations to find this value; it can be easily calculated. (The 150% assumption is another way of saying, "assume the output transformer impedance is 10% on a base of the generator maximum real power" -- and it often isn't.) If you want to be sure to cover all possible real power loadings, draw a horizontal line across the PQ plane parallel to the P axis at this value. (This is true unless we assume a voltage depression will only happen at certain loadings -- why? which ones?) This horizontal line corresponds to a mho circle with a diameter equal to Xt/0.15, 90 degrees MTA, and zero offset. So if the goal is, "permit generators to ride through 0.85 pu transmission voltage depressions without tripping on 21 relays", then require that 21 settings lie inside a mho circle with a diameter/reach of Xt/(0.15 * 1.15), 90 degrees MTA, and zero offset. (The 1.15 is the 115% calibration fudge factor.) The technical basis does not support asking for more than this, and asking for less will not accomplish the apparent objective unless we can somehow guarantee that we don't care about spurious trips at certain loadings (which may be due to power swings.) In my opinion, analysis should precede simulation.
No
There are three issues: (1) on-load tap changers for output transformers are not handled, (2) the 150% reactive outflow assumption is not appropriate when using the calculation option as you can calculate the actual VAR outflow for a 0.85 pu voltage depression quite easily from the transformer impedance unless initial conditions with heavy VAR flows are assumed, and (3) the initial conditions for the simulation are not specified (full load and unity power factor with all voltages at 1 pu?) and the conditions for simulating the voltage depression are not specified (no swings or close-in faults?)
Yes
NOT APPLICABLE IN MY JURISDICTION
Get rid of the 150% assumption. It can be calculated directly from transformer impedance. Get rid of the special cases -- there are too many, such as load tap changers, that you are not handling. Simply require that generators' 21 relays be set to ride through the consequences of a 0.85% transmission voltage depression with 115% fudge factor, and specify the loading range you care about for special cases. This works out to a mho circle, diameter=Xt/(0.15 * 1.15), MTA=90 degrees, zero offset. Compliance verification is a straightforward engineering

exercise.
Group
Southwest Power Pool Regional Entity
Emily Pennel
Yes
Yes
Yes
Yes
Since this standard isn’t enforceable until 48 months after approval, why not make the effective date 48 months after approval? This would reduce confusion concerning Registered Entities’ requirements for performance (such as outage scheduling and early adoption) during the 48 month implementation period.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
No
In the case where existing protective relay replacement may be necessary, 48 months does not provide adequate time to budget, design, coordinate, procure materials, and schedule the work that would have to be done during outage of sufficient duration. Suggest extending the Implementation Plan duration to 60 months.
Individual
Thad Ness
American Electric Power
Yes
No
AEP has the following concerns regarding the settings options. The 0.85 per unit transmission bus voltage will never be seen by Generators with a delta connection to the Generator Step Up transformer. In order to drop the generator bus voltage to support the 0.85 transmission bus voltage, the unit would need to reduce the Real Power output. Even with reducing the Real Power output and increasing the Reactive Power output, the unit may not be able to withstand the lower voltage. Motors may trip out when connected to a lower generator bus voltage, which could cause additional operating issues and potentially leading to a trip of the unit itself.
No
Generation relay settings typically use the generator bus voltage for calculations. Options 2, 3, 6, 7, 10, 11, 12, 14, 15 and 17 are all expressed as .85 per unit of the transmission system, but should instead be referenced in regards to the generator bus voltage (as Options 1, 4, 5, 8, 9, 13, and 16 are). Phase distance relays (21) listed in Table 1 should be excluded from any requirements in PRC-023-2- Transmission Relay Loadability. The phase distance relays included in Table 1 can only have settings that will be compliant with one set of requirements not both. Inclusion of these relays in PRC-023-2 and PRC-025-1 would pose a conflict in settings. Also the out of step relays (78) were listed in PRC-023-2. However, AEP believes that these relays should also be included in Table 1 as a requirement in addition to being an exclusion from PRC-023-2. “Seasonal gross Real Power capability” needs to be explicitly defined.
No
Due to the expanded scope of this project and the resulting (proposed) requirements, a significant amount of research and studies may need to be performed in order to properly inventory the existing relays and determine

their settings. This is not an automated process, and would require extensive print reviews and field verification. The proposed implementation plan emphasizes the time needed to change the relay settings, but deemphasizes the time and effort required to inventory the relays, determine their current settings, and perform the calculations required to determine the new settings. For entities with a large generating fleet, this phase alone could take four years or more to accomplish. Again, this would include the time and resources necessary to actually make those setting changes in the field. Rather than requiring that all research and implementation be completed within 48 months, a time period much too short to perform the work necessary to meet the requirement, AEP believes this standard should instead utilize the precedent of a phased-in approach over 10 years (for example, 50% complete in 4 years, 75% in 7 years and 100% in 10 years). In addition, the work required for this project requires a specific expertise held by a limited number of subject matter experts, and who are also needed to implement other NERC standards and support ongoing reliability efforts. This further supports the need to extend the time allotted beyond four years.
Are transformers which are independent of the generator bus, and are fed from the grid, in scope? Figure 1 seems to infer the inclusion of such devices, but if so, that is not made explicit within the description provided in 3.2.3 and Note 1. Both 3.2.3 and Note 1 need to be more specific or refer to an attachment for examples. This standard does not explicitly state which auxiliary transformers are in scope. AEP recommends clearly identifying whether the standard is applicable to Reserve Auxiliary Transformers. In addition, Footnote 1's second sentence should be modified to state "Loss of these transformers will result in the generator's immediate removal from service." The scope of this draft is inconsistent with the title and purpose with respect to generator protective relays as opposed to generation relays. The phrase "generator relay" has a specific meaning to a relay engineer, and encompasses only a subset of the generation relays covered under this standard.
Individual
Michael Falvo
Independent Electricity System Operator
No
a. Requirement R1 seems clear but replacing the word "install" with "implement" or "determine" would seem more appropriate that the settings are not exactly "installed". If the SDT accepts this proposed change, then conforming changes need to be made to M1 and throughout the entire standard. b. The language in M1 seems unclear to convey the evidence needed to be provided to demonstrate compliance with R1. We suggest M1 be revised to: For each load-responsive protective relay, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed (suggest to replace it with determined or implemented) in accordance with PRC-025-1 – Attachment 1: Relay Settings.
The proposed effective date in the implementation plan may not clearly address a potential conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that the sentence be re-arranged as follows: [First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees.]
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
Entities may have situations where appropriate equipment protection cannot be met and accommodate the load-responsive requirements of Attachment 1. For these rare cases there should be some provision established to allow the Entities to maintain compliance. The wording of R1 should be changed to clarify that the relay settings applied to load responsive relays must meet or exceed the requirements in Attachment 1. The present wording could be interpreted to require that the load responsive relay settings must be set exactly as prescribed in Attachment 1.
No
Considering Figures 1 & 2, it is unclear whether the intent is to include station auxiliary transformers that feed plant loads when the unit is offline or in the process of startup. An exception should be made for transformers that do not feed plant loads during normal unit online operation.
No
Paragraph 2 of Attachment 1 starting with "Synchronous generator output pickup setting criteria values are determined……" seems to contradict Table 1 regarding the calculation of reactive power output. The paragraph

implies that reactive power capability is calculated using the rated power factor however Table 1 implies that it is calculated as a function of rated MW output. It would greatly enhance understanding of Table 1 if some examples calculations. This would allow entities to be confident that they were interpreting the wording of the requirements correctly.
No
The 48 month time period may not allow enough time to engineer and then schedule the work necessary to implement the changes. The work required to implement new relaying schemes may be intensive if new relays need to be installed. This type of work requires extended outages that may not occur on an annual or even bi-annual basis. The implementation plan should be modified to at least 60 months.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
No
We would suggest that the table be broken up into different tables based on the application of the relay. For example one table for synchronous machines, one table for GSUs, one table for AUX transformers etc..
Yes
Group
Pepco Holdings Inc. & Affiliates
David Thorne
No
Requirement R1 and the wording in Attachment 1 require the GO to install settings on “each load responsive protective relay” in accordance with Attachment 1, Table 1. The standard should make it clear that it does not apply to any load responsive relay (i.e., phase overcurrent protection) that is armed only when the generator is disconnected from the system, or enabled only during generator start-up (i.e., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, open breaker flashover schemes, etc.). Nor should it apply to any phase fault detector relays employed to supervise phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) providing the distance element is set in accordance with the criteria outlined in the standard.
No
Section 3.1 and Appendix E of the NERC SPSC Technical Reference Document “Power Plant and Transmission System Protection Coordination” describes two separate loading points that should be examined to ensure adequate generator relay loadability during extreme system conditions. One is the loading condition chosen in PRC-025-1 (MW = rated MW ; MVAR = 1.5 x rated MW). The other loading condition is with a lower power output, but with a higher var output (MW= 0.4 x rated MW ; MVAR = 1.75 x rated MW). The SPCS document illustrates that depending on the maximum torque angle setting of the distance element that this second loading condition may become the limiting criteria. The Technical Basis and Guidelines in PRC-025-1 refers to this SPCS document several times, but it does not mention this second loading condition, or the rationale for ignoring it when developing the chosen setting criteria.
No
1) Options 1, 5 and 13 should be eliminated, or a qualification should be added that these options may only be used if the generator step-up transformer reactance is greater than some specified threshold amount. It is true that due to the voltage drop across the transformer, the generator voltage will be higher than the system voltage. This can be seen from the following equation: Vgen = Vsys + Igen x (j Xt). Assume the generator is operating at a loading condition of S = 1.532@56.31 pu MVA, which is the maximum anticipated loading condition identified both in this standard, as well as in the SPCS document (ref. Appendix E). Assume the generator voltage Vgen is 0.95@0 pu, as allowed in Options 1, 5, and 13. Since S = VI*, Igen can be found as 1.613@-56.31 pu. By then solving for Vsys, one can see that Vsys will be greater than 0.85 pu, whenever Xt is smaller than 0.076pu (Xt < 7.6%). While most GSU transformers have a reactance equal to, or greater, than this value, some may not. Since all loadability criteria must be based on a system voltage of 0.85 pu, the choice of Vgen = 0.95 pu is appropriate only if the application is restricted to GSU’s with sufficient reactance to ensure the application results in a

corresponding system voltage of 0.85 pu, or lower. Options 2, 3, 6, 7, 14, and 15 are not an issue, because they assume a system voltage of 0.85 pu and then require a calculation, or simulation, to obtain the corresponding generator voltage to be used in the evaluation. Finally, if the SDT decides to retain Options 1, 5, and 13 then the Guidelines and Technical Basis section should be revised to address the technical justification for the choice of a 0.95 pu generator voltage. 2) The ANSI number 51V-R should be used instead of 51V to represent voltage restrained overcurrent relays, and 51V-C should be used instead of 51C to represent voltage controlled overcurrent relays. Using 51V-R and 51V-C avoids confusion, since 51V is often used to represent both types of relays. Also the 51V-R and 51V-C terminology is consistent with that used in the SPCS Technical Reference Document. 3) In the Guidelines and Technical Basis portion of the standard it states "If a mho phase distance relay cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics." However, the standard does not provide any specific criteria, or methodology, on how to evaluate relay loadability if these techniques are employed. Table 1 simply states that the 21 element (assumed to be a non-offset mho element) should be set with a maximum reach less than the apparent impedance described, apparently regardless of the setting of the maximum torque angle of the relay. If blinders, or load encroachment techniques were used to accommodate the one specific loadability point described in the standard, aren't there other loadability constraints that also need to be addressed? The Technical Basis portion of the standard points out the concern that altering the shape to achieve a longer reach may restrict the capability of the unit when operating at a real power output other than 100%. Therefore, to cover all applications, the PRC-025-1 standard should describe loadability criteria irrespective of the type, or shape, of the impedance characteristic used. To accomplish this, perhaps a better set of setting criteria would be as follows: "The phase distance protective characteristic should be set, assuming a generator voltage as specified in the column labeled bus voltage, so as to not operate under any of the following three loading conditions: a) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (100% of Maximum MW; Reactive Power equal to 150% of rated MW). b) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (40% of Maximum MW; Reactive Power equal to 175% of rated MW). c) Generator supplying power (as measured at the generator terminals) within its published capability curve." Plotting these three constraints on the R-X impedance plane would allow one to choose a phase distance characteristic (with, or without, load encroachment, or blinders) that would be immune from operating under these specific loading conditions. The third condition would effectively limit the reach of the element so as to not restrict the reactive capability of the unit. This last issue is very important, since in the latest draft of PRC-019 the coordination of the phase distance element with the generator reactive capability curve was specifically removed, implying that it would be addressed in the PRC-025 loadability standard.
Yes
Group
ACES Power Marketing Standards Collaborators
Ben Engelby
No
(1) There is potential for double jeopardy with PRC-025-1 and PRC-023-2. PRC-023-2 also applies to relays on GSU transformers under 100kV. Collectively, applicability section 4.2.1.6 and Attachment A, 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that "forms a path." With this proposed standard, a GO/GOP could be found in violation of both PRC-023-2 and PRC-025-1 for not having appropriate relay loadability settings. We strongly suggest that the SDT consider revising PRC-023-2 to remove all references to Generators in order to avoid any possible instances of double jeopardy. This would be consistent with FERC Order 733, paragraph 106, "we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability." If generator loadability is going to be addressed in its own standard, then it should not overlap with transmission relay loadability and PRC-023. (2) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls and elimination of zero-defect expectations). To refocus NERC efforts on compliance, the recent compliance enforcement initiatives would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this requirement. As an example, what happens if a GO miscalculates their setting or inadvertently uses the wrong setting for one unit? This should not be a violation, per se, if the GO discovers it and corrects it. (3) We are concerned that this standard also duplicates the proposed PRC-024-1 of Project 2007-09 Generator Verification. Proposed PRC-024-1 requires a GO to ensure its voltage protective relaying does not trip as a result of a voltage excursion. Does the voltage control relaying include Phase-Time Overcurrent Relay (51V) voltage-restrained from Table 1 in Attachment 1 of proposed

PRC-025-1? Is the 0.85 pu voltage identified in the same table not a voltage excursion? If so, this duplication needs to be eliminated. (4) The standard needs some clear flexibility built into it to deviate from the settings in Attachment 1. Consider an example where a GO sets its phase distance relay on its synchronous generator to meet option 1 and an event causes the unit to trip anyway. The GO should be allowed to reassess and apply an appropriate setting even it if deviates from the Attachment 1 relay settings.
No
(1) Paragraph 102 of FERC Order 733 does not provide adequate rationale for attachment 1. Paragraph 102 in the Order is discussing Entergy's treatment of GSU and auxiliary transformers. This question is inaccurate and needs to be clarified in order to provide an appropriate answer. (2) If the drafting team is referring to paragraph 104, by addressing GSU and auxiliary transformer loadability is addressed in a timely manner and in a way that is coordinated with the outcomes of PRC-023-1, we feel there is more coordination that must be done. Currently, PRC-023-2 is now in effect and potentially has applicability requirements for GSUs and auxiliary transformers. For example, applicability section 4.2.1.6 and Attachment A 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that "forms a path." The drafting team must separate the standards to avoid overlap. While we understand that the Commission did not require a separate standard, now that NERC that decided to approach this issue by developing PRC-025-1, it needs to revise PRC-023-2 as well. (3) The technical document that is referenced, "NERC Technical Reference on Power Plant and Transmission System Protection Coordination" explicitly states that "there is limited information available that directly addresses which protection functions are appropriate for BES conditions and which were undesired operations." This document is prefaced with the fact that the authors are unsure of what are appropriate settings for protective relays; rather it addresses the coordination of each of the generator protection functions with the transmission system protection. This is not adequate rationale.
No
(1) We find the criteria confusing and needing further clarification. First, we suggest dividing the table into multiple tables based on the relay type and application. This will make it clear that GO does not have 17 options but rather has only three options for Phase Distance Relays (21) protecting synchronous generators. Second, we are confused about the difference in the bus voltage column for options 1 and 2. Both options apply to the generator bus and voltage is calculated from the high side of the generator step up (GSU) voltage. Option 1 allows the voltage to be set at 0.95 pu and option 2 allows the voltage to be set at 0.85. Option 2 mentions using the GSU impedance in addition to the turns ratio to calculate the generator bus voltage from the high side whereas option 1 only mentions the turns ratio. If the intention is to include the GSU impedance in one calculation and not the other, does it make sense to have a voltage difference of 10%? To drop voltage 10% across a GSU would require a very high impedance transformer. Please provide further clarification. As currently defined, we believe that option 1 will always be selected because it is simply less restrictive. We note that similar issues exist between Options 5 and 6 and Options 13 and 14. We assume the voltage identified in the bus voltage column of options 10-12 applies to the generator bus. It is not clear if the impedance of the GSU is to be considered for these options. We assume it would be but there is so much less information provided than in the other options so it is not clear and is not explained in the technical guidelines.
No
(1) The implementation plan is unreasonable in the amount of time needed to have generation units comply with the standard, especially with the considerations of having to replace existing protective relays, meeting budgetary concerns, coordination with other entities, the time for procurement, and planning outages to complete the necessary work. We suggest 60 months. (2) As mentioned above, there are overlaps with this standard and the applicability section and implementation plan for PRC-023-2. If a generator was subject to PRC-023-2 as a result of being designated by its Planning Coordinator, it would have the "later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date." The drafting team needs to review the applicable time frames, modify PRC-023-2 and provide a clear and understandable timeline that does not have conflicting standards interfering with its implementation. (3) We strongly suggest that the drafting team review PRC-023-2's implementation plan for GO/GOPs and modify both standards to avoid overlap, confusion, and as discussed above, double jeopardy.
(1) We have concerns with the drafting team's approach of requiring replacement of legacy relays for the sake of complying with its proposed standard. This additional strain on resources will have an adverse impact for smaller entities. Smaller entities do not have unlimited budgets and it is difficult to justify the replacement of working equipment just to comply with a regulation. The regulators need to consider reevaluating the threshold that is needed to comply with this standard. If a protection relay is not broken, there should not be a reason to replace it. There is not sufficient justification that having a modern advanced-technology relay with extra functionalities to have a reliability benefit that is commensurate with the cost. (2) We suggest the drafting team complete the VSL table and provide a draft RSAW of this standard. PRC-023-2 is currently in effect and there is no guidance or RSAW posted, which results in a tremendous amount of confusion on how to comply with the standard. We strongly suggest that the SDT plan for how the industry will need to comply with PRC-025-1 and provide a sample

RSAW. Also, if this standard is results-based, then is it possible to consider internal controls for the responsible entity to correct relay settings without consequences of self reporting? (3) We disagree with the setting of a high VRF for Requirement R1. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with the NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. A Medium VRF is more appropriate. (4) We disagree with the statement "that it may be necessary to replace the legacy relay with a modern advanced-technology" on page 14 in the Guidelines and Technical Basis section. Section 215(i)(2) is very clear that the ERO or Commission are not authorized to order construction. Thus, a standard cannot compel relay replacement. (5) There is text in the comment form regarding using a Method 1 or Method 2 for relay loadability. We can find no mention of these methods in the standard or Guidelines and Technical Basis. The methods actually require calculating loadability at two operating points. While one of the points appears to be Pick-up Setting Criteria in Table 1 of Attachment 1, the other is not referenced anywhere in the standard. Please include this section in the standard as appropriate or remove it from the comment form as its purpose is very confusing. (6) Thank you for the opportunity to comment.
Group
North American Generator Forum Standards Review Team
Jim Watson
Agree
North American Generator Forum Standards Review Team
Individual
Travis Metcalfe
Tacoma Power
Yes
Yes
No
Referring to Attachment 1, Table 1, Options 2, 3, 6, 7, 14 & 15, what current is to be applied through the transformer impedance? Referring to Attachment 1, Table 1, Options 10, 11, 13, 14 & 15, should "Real Power output – 100% of connected generation reported" be changed to something like "Real Power output – 100% of maximum seasonal, aggregate gross MW reported to the Planning Coordinator"? Referring to Attachment 1, Table 1, Options 10, 11 & 12, could an exception be granted if the 51 elements are directional toward the generation system? Referring to Attachment 1, Table 1, Option 17, should "the element shall be set greater than the calculated current derived from 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating" be changed to something like "the element shall be set greater than 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating"?
Yes
Referring to the first paragraph of Attachment 1, Options 1-17 are not truly exclusive options. Options 1-3, Options 5-7, Options 10 & 11, and Options 13-15 each appear to be exclusive options. However, an entity may, for example, need to apply Options 1, 2 or 3 together with Options 10 or 11 together with Option 17. Consider separating Table 1 into multiple tables, each table based upon a different combination of relay type and application. Each option within each table would then be exclusive.
Group
Salt River Project
Bob Steiger
Yes
Yes
Yes
Yes

No additional comments.
Group
Detroit Edison
Kent Kujala
No
The intent of the requirement is clear, but the specifics of how to accomplish it are not. Not sure of the meaning of “performance” in this context.
No
With the exception of Auxiliary Transformers, this standard appears to be concerned with relay elements that operate for power flow toward the transmission system. Distance elements and directional overcurrent relays not “looking” toward the transmission system should not be in scope. Perhaps a statement to this effect in the Technical Basis would be beneficial.
No
Please provide setting examples for each type of relay (21, 51V, etc) using both real and reactive power criteria to clarify how Table 1 should be applied. Also, drawings showing location of applicable relays (CT and PT input sources) would be helpful. Reactive power criteria expressed in terms of MW is confusing.
No
Suggest that allowing 72 months to become 100% compliant would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No
The objectives of the following NERC Standards closely match the objectives of the proposed standard, MOD-024, MOD-025(pending regulatory approval) and PRC-019 (Standard under development). Entergy is currently validating the maximum generator capability under SERC criteria for MOD-024 and MOD-025. This validation requires coordination with applicable load responsive relays.
Group
MRO NSRF
Will Smith
No
The NSRF is concerned that Measure M1 does not take into consideration situations in which existing relay settings are already in compliance with the standard but the setting calculations are not dated and/or the actual date that the settings were installed is not known. To better align with the risk-based requirement, the NSRF recommends M1 be revised to only require evidence showing that the relays settings were in compliance prior to the enforcement date. M1. For each load-responsive protective relay in accordance with PRC-025-1 – Attachment 1: Relay Settings, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed in compliance with Requirement R1.
No
Recommend the phrase “while maintaining reliable protection” be removed as it introduces ambiguity into R1. Although the SDT attempts to clarify the phrase within the “Guidelines and Technical Basis”, the NSRF is concerned that the phrase’s inclusion will only result in future requests for Interpretation as entities are forced to explain and defend their desired protection goals. Rather than relyon the “Guidelines and Technical Basis”, werecommendthe following changes to R1 be made: R1. Each Generator Owner shall install settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection.
No

The NSRF agrees with the criteria described in Option 1 through 17 in Table 1, however, we recommend that the Table 1 be broken up into different tables based on the application and relay type. For example, there should be a table for synchronous machines, and one for GSUs, and etc. This would add clarity to Table 1. The addition of the new tables would require that the Application Guidelines section to refer to the new tables be revised.
Yes
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
It is clear the Generator must determine and install settings on its load-responsive protective relays in accordance with PRC-025-1.
No
Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity.
No
Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity.
Yes
LADWP agrees the Implementation Plan to install load-responsive protective relay settings is achievable in 48 months.
For the Transmission Relay Loadabiltiy Program, examples and job aids were provided to establish a uniform method to calculate relay settings. Examples and job aids should also be included for Generator Relay Loadability.
Individual
Saul Rojas
New York Power Authority
No
There was no mention of load responsive relays on an Exciter PPT which is connected to the terminal side of the Generator. There was also no mention of any load responsive relays connected to the ISO Phase Bus between the Generator and the Unit Auxiliary Transformer or the secondary side of the Unit Aux Transformer.
No
For the Unit Auxiliary Transformer, the Technical Basis and Guidelines does not take into account the 51 element being set below 150% of rated but with a significant time delay setting to provide backup protection for the feeder protection.
No
Yes for Option 1-16; No for Option 17 as stated in Question 2.
Yes
Individual
Nazra Gladu
Manitoba Hydro
Yes
(1) It is not clear what this question means by the "performance of Requirement R1". If it means that Requirement R1 (and Measure M1) is clear, then yes it is. (2) R1: The phrase 'while maintaining reliable protection' is extremely

ambiguous. We noted that in the rationale, the reader is referred to the Guidelines for elaboration on this phrase. The discussion in the Guideline did little to clarify in our opinion; it discusses balancing the standard and the entity's desired protection plan. Is the standard not mandatory and the entity's overall plan for reliability and protection needs to incorporate the satisfaction of this standard (and others)? (3) M1: The measure as drafted fails to address whether the entity missed installing relays that are required by Attachment A, it is only looking for evidence specifically related to those relays that were installed in accordance with Attachment A.
Yes
No comment.
No
(1) For all 21 - Phase Distance Relays (Option 1 – 4 and Option 13 – 16): The setting criteria did not mention the maximum reach angle of the impedance element setting. Should this be considered and clarified? (2) For 51V – Phase Time Overcurrent Relays, voltage-restrained, (Option 5 & 6): Following this setting criteria could make detecting faults on the high side of the step-up transformer very difficult especially considering that transient or synchronous machine impedance (X'd or Xd instead of X"d) is used for fault calculation. (3) For the 51 relays on the step-up transformers (Option 10): Following this setting criteria could mean that the pickup setting could be 175% of nameplate rating of the transformers. Should there be any concern with the transformer overload and mechanical damage as a result? Also, the 175% setting is not consistent with the 150% number in the Transmission Relay Loadability standard. (4) The "Bus Voltage" criteria are not clearly defined and should be clarified. For example, in Option 1, the generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage would vary depending on the current going through the transformer. Also, option 2 in the table makes reference to "on the high side" and option 1 in the table makes reference to "of the high side". Should these all read 'of'? (5) Given 'gross MW' and 'terminal voltage', how would we calculate current in order to calculate the generator bus voltage? (6) What is meant by "maximum seasonal gross MW"? Is this the nameplate MW? Is this the MW calculated for MOD-024? If so, a reference should be made to this standard.
Yes
Although we agree with the implementation plan, the Applicable Entities should match the language in the standard i.e. Generator Owners 'that applies….' The language in the Implementation Plan section is awkward in that they refer to 'protective relays applicable to this standard' when it would seem to make more sense to refer to 'protective relays to which this standard applies'.
(1) Regarding "Applicability", it is not clear what type of auxiliary transformers should be included as the "Applicable Facilities". For example, if the auxiliary transformer is NOT the only supply to the generator, does the standard still apply to this auxiliary transformer? (2) On page 7 of 22, the following sentence is unclear: "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in Megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor". Manitoba Hydro suggests rewording this sentence for clarification. Additionally, should "rated MW" be changed to "rated MVAR'? (3) On page 3, A Introduction, Purpose: We find the purpose quite poorly worded as it stands. It is written in absolutes (i.e. generators do not trip, disturbances that are not damaging) which is quite different than the wording used in the Background to describe the standards (i.e. that did not apparently pose a direct risk). It would seem more appropriate to use language that discusses the purpose as opposed to the outcome. For example, language similar to "To set load responsive generator protective relays at a level designed to prevent tripping of generators during system disturbances that do not apparently pose a direct risk to the generator in order to prevent the unnecessary removal of the generator from service.' (4) On page 3, A Introduction, Applicability, 3.1.1: The standard uses the term Generator Owner in terms of functional entities. However, the definition of Generator Owner only makes reference to owner of generating units. Does that still work with 3.2.2 and 3.2.3 which includes Elements other than generating units? (5) On page 3, A Introduction, Background: Does this 'Background' section become part of the standard once finalized? (6) Attachment A: The opening line should refer to each Generator Owner that applies load-responsive protective relays on the Facilities listed in 3.2 in order to be consistent with the applicability section of the standard itself. (7) Revisions or Retirements to Already Approved Standards: There is a reference to Order NO. 733, paragraph 102. We believe that this needs some elaboration because we are not sure that paragraph sets out the requirement that is in the standard.
Group
pacificorp
ryan millard
Yes
Yes
No

PacifiCorp thermal facilities use impedance elements as backup generators, generator bus and GSU protection where the element does not reach through the GSU. This approach results in impedance magnitudes that are significantly lower than those outlined in the Attachment 1 options. It may be beneficial to generator protection engineers if the standard provides registered entities with an option to calculate the impedance reach of the 21 element when it is based on the GSU impedance. Furthermore, while Options 1-4 & 13-16 in Table 1 specify how to determine the generation facility maximum rating and the per-unit bus voltage to perform the impedance reach calculation, these options are missing: (1) the load (or power factor) angles at which the impedance element reach must be evaluated to ensure compliance, and (2) recommendations as to how to set load-encroachment element blinders. PacifiCorp recommends that this information be incorporated into the "Guideline and Technical Basis" section of PRC-025-1 to ensure compliance, using Standard PRC-023-2 "Reference Document" as a model.
Yes
The use of the term "Bulk Electric System generation Facilities" in the Applicability Section 3.2 of the standard is not explicitly defined. PacifiCorp recommends that the Standards Drafting Team include generator size to further refine the applicability of facilities under this standard.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP ("ICLP") agrees that the instruction is clear in both R1 and M1, but does not agree that the language meets the intent of a "risk-based requirement." The concept, as we understand it, is to focus on the quality of the process which manages the implementation of the settings – not a confirmation that the settings are always perfectly compliant. There is no risk at all inherent in R1, excluding that to the unfortunate Generator Owner who happens to miss-set a single relay. We suggest a preface to R1 similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". This will allow some flexibility when a rare error takes place – while accounting for those entities whose internal controls are not sufficient to the task. In addition, the language addresses those situations where a NERC-compliant setting is not possible without placing equipment or safety at risk.
Yes
From a technical perspective, Ingleside Cogeneration found this section was soundly grounded. However, we believe that there is no rational basis that the standard apply to generators which have minimal impact on BES reliability – analogous to the 200 kV voltage threshold for transmission lines in PRC-023-2. The justification needs to be captured in the Technical Basis and Guidelines section, although the criteria itself would appear in the Applicability section. Secondly, there needs to be further discussion concerning the interaction of the relay loadability thresholds with those required under Project 2007-09 Generation Verification – particularly PRC-024-1 and PRC-019-1. At present, every one of these standards are written in a manner that calls for the Generator Owner to comply with their requirements, and to figure out how to make them all work together. Even though we agree that the ultimate goal to improve generator availability will greatly serve BES reliability, ICLP does not believe this kind of approach is reasonable – and may lead to violations even when the GO is heavily committed to the task.
Yes
No
Similar to PRC-024-1, ICLP believes there needs to be an allowance for those equipment types which cannot accommodate the Table 1 settings. In particular, the variation in the ancillary systems which support the generator is significant – and 48 months will not be sufficient to address every situation.
ICLP believes that NERC's Compliance organization should be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason.
Individual
Timothy Brown
Idaho Power Company
Yes
Yes
Yes

Yes
Based on the language of Section 3.2.3, which describes the applicable facilities, we believe some addtional clarification should be added to Footnote 1. Many modern static excitation systems have a sizable dedicated transformer. We believe a mention of these excitation transformers would provide needed clarification.
Group
Southern Company (Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Company Generation, Southern Company Generation Energy Market)
Shammara Hasty
No
The requirement is clear - the protective relay setting specifications are not acceptable. We believe that using "apply settings" rather than "install settings" in Requirement R1 better suits the accepted terminology for setting the protective device parameters. The phrase "while maintaining reliable protection" in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with "achieving …desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, our desired protection level is more conservative so that generation equipment is not allowed to be operated in overloaded conditions. Our experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specificed in Table 1 and not result in undesirable nuisance tripping.
No
The rationale seems to ignore the fact that most generators do not operate any of their equipment beyond the manufacturer's ratings in overloaded conditions. The practices suggested by Table 1 seem to be patterned on transmission line loading practices, which are different than the practices used by generators. Generator step up transformers and station auxiliary transformers are generally not allowed to be subjected to short term overload conditions. We disagree with the suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18. Suggesting that an entity's existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing philosopy of protection used by many companies has proven (over multiple decades) to be adequate for protecting our equipment and providing reliable power supply to customers. The NERC Glossary states the following definition for Equipment Rating: "The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner." The acceptable amount of risk to power equipment evident through margin in the protection settings rests with the equipment owner. We are concerned that the NERC standards will take this away from the equipment owner. This is especially concerning where automatic protection is required and must operate quickly to prevent significant major equipment damage. Reliance on operator intervention to protect the equipment, in this case, is not practical. Adequate margins of protection must be allowed to be maintained in the automatic trip settings. We believe adequate protection is a fundamental tenet for BES reliability to ensure the equipment can be restored to service quickly.
No
Fundamentally, requiring entities to relax preferred protection levels on their equipment with no method of (possible) damage cost recuperation due to more liberal protection settings is not fair to the entities that may incur repair/replacement costs. We believe that Option 17, related to station auxiliary transformers, is unwarranted, excessively liberal in overload allowance, and does not belong in this standard. The station auxiliary power consumption does not directly contribute to the generator overload ability for supporting system disturbance events. Requiring a station auxiliary transformer HSOC (high side overcurrent) relay to be set at the level specified in Option 17 of Table 1 is not justified. We have, for many years, successfully set the station auxiliary transformer HSOC relay pick up value at a much lower value and have experienced very few misoperations. The MW value used in the calculation specifics of Table 1 is unclear. We suggest that the MW value used for the calculations be that realized with applying the generator nameplate MVA rating with the rated power factor also found on the generator nameplate. In the draft standard, the MW value to be used is referred to by many different names, including: •Maximum seasonal gross MW reported to the Planning Coordinator •Rated MW •Total nameplate MW •100% of Connected generation reported Establishing the MW value as suggested above removes all confusion to the GO as to which MW value to use, provides a standard method to use, and is close enough to the other values listed to provide the desired generator loading ability. Table 1 is much too complicated. Options 1-4 and Options 13-16 could easily be combined into one set of four options by modifying the Application column. (For example, the combined Options 1 and Option 4 Application column could be labeled "Synchronous Generator or GSU Xfmr – Synchronous Generator".) Further, Options 1-3 and Options 13-15 should be reduced into one row that specifies the Generator Bus Voltage criteria and the Pickup setting criteria. The additional methods listed (Options 2, 3, 14, 15) simply confuse the issue. (For example, it is not clear which entity is

required to perform a simulation in Options 3, 7, and 15. GO's generally do not have the system simulation software or the system data required to perform this simulation.) For the rows of Table which remain after this simplification, one calculation example per row would be valuable to demonstrate the intented calculation method. We are concerned that the setting limits specific in Table 1 are too liberal to provide adequate overload protection to our generating plant equipment. The required minimum sensitivities for the relaying shown in Table 1 for all units based on a minority (20%) representation of unit capability to provide Q forcing ability results in forcing owners of generators to relax typical relay settings that result in loss of adequate overload protection. Entities should be allowed to protect their equipment from overload rather than be forced to allow a specific amount of overload.
No
The implementation plan for execution of Requirement R1, as written, is too short. This requirement will cause GOs to have to check calculations for every relay in the scope of Table 1 for all of its facilities. Checking the setting limits agains the equipment safety levels will take significant time. Equipment procurement, where necessary, and unit outage availability will dictate the exact time required to address the scope of the applicability. It is recommended that the implementation time be increased to 7 years.
Yes. In Applicability Section 3.2, we disagree with the specifier "including those identified as Blackstart Resources in the TOP's system restoration plan". The additional small units this may draw in to the scope of this standard are not large enough to be significant contributors to correcting frequency and voltage perturbations on the transmission network. The word "overall" does not add any value to applicability section 3.2.3. If the voltage restrained overcurrent relay is the primary relay of concern (as noted from the 14 Aug 2003 disturbance), perhaps the solution is to require that they are replaced with alternative types of relaying rather than by specifying the desensitizing setting specifications. We have real, historical cases where a generator back-up overcurrent relays set at 115 to 130% of the unit rating have saved the units that were exposed to either a low-level, close transmission faults or excitation system malfunctions. A possible solution to generator relaying modifications to provide the maximum allowable loadability for supporting system disturbance events may be to remove all voltage restrained/controlled overcurrent relays and replace them with a standard 51 function. This relay could be set just under the generator ANSI overload curve to protect the unit from low level overload. This would give plenty of area for swings while still protecting the generator. The 21 function could then be adjusted to pickup at 180 to 200% of the units MVA rating with appropriate time delay to coordinate with transmission Zone 3 relays. An alternative solution to specifying the generator relay settings is to allow the PRC-001 standard (currently under draft) to take care of the desired coordination between generator relaying and transmission system relaying. In that standard, the GO and TO must confer with one another regarding the coordination of the generator relaying and the transmission system relaying. The loadability issue of generators, we believe, can be adequately resolved by the coordination requirements to be contained in PRC-001.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Yes
Yes
Group
Dominion
Mike Garton
Yes
Yes
Yes
No
In the case where existing protective relay replacement may be necessary, Dominion does not feel that 48 months

provides adequate time to budget, design, coordinate, procure materials, and schedule the work in an outage of sufficient duration. Dominion suggests that 60 months may be more appropriate in this instance.
Group
Duke Energy
Greg Rowland
No
1) R1 states that protection must meet the criteria and be reliable - this is not possible. Protection is often considered an artform, since it includes making compromising decisions between dependability and security. This standard, by its nature, is biased toward security. It requires relays to be set such that they can no longer be depended upon to prevent potential damaging operating conditions. 2) In its current form, this standard seems to disregard the factor of time, as it relates to equipment withstand for the specified system conditions. For example, Table 1 will require 51T relays on the GSU not to pickup before 2.2pu (for a machine rated .9pf), even though the transformer through-fault protection curve of IEEE C57.12 does not support continuous operation at that point and the generator stator thermal limit, per IEEE C50.13, is less than 10 seconds. Requiring the GO to permit operation of equipment outside American national equipment standards is incongruent with improving the reliability of the BES. 3) In section M1 on pp4/22: reword to "(2) Record Settings"
No
It is difficult to comment on the criteria, as we are not familiar with the train of thought used to derive them. Not all of the criteria are described in the Technical Basis section.
No
1) If such a table is used; RELAY TYPE should simply be the type of element, such as "Phase Distance - 21", and APPLICATION should be the elements use, such as "Applied on synchronous generator, set to trip for faults in the system direction." Further, the SDT should not separate BUS VOLTAGE and what is called PICKUP SETTING CRITERIA - Together these are defining the system conditions for which the relay is not supposed to pickup. 2) It is not clear what the intent of the 115% factors specified in Table 1 are. If these are for coordinating margin, this should be expressed so coordination margins are not doubled. 3) We recommend using the common designations of 51VC for voltage controlled inverse time overcurrent elements and 51VR for voltage restrained inverse time overcurrent elements. 4) SDT should specify criteria in standard engineering terms. The use of language such as "VArs equal to 150% of rated MW" is not clear. It would be better to specify "Rated Watts at .55 pf lagging." 5) We do not understand the differences between several of the options, such as between option 1 & 2. Option 1 is not aligned with Appendix E of the technical guide, and no commentary is provided within the standard. SDT is creating criteria that are outside the mainstream - it must provide more technical information on what the intent and rationale is for each criteria. 6) The intent of options 13-16 is not clear. Are these for 21 elements on the high voltage of GSU? If so, why are generator terminal voltages mentioned? 7) We question whether all of the options are required. Many of the system conditions are the same from one application to another. Could the worst case system conditions be presented in paragraph form along with descriptive commentary? 8) SDT should consider including recommendations for the traditional 50/27 elements used for inadvertent energization protection. Traditionally the 50 elements of this type are set near 1.5pu. The setting of the voltage element needs to be evaluated such that it will ride through disturbances but also sense voltage during a true inadvertent energization under worst case system conditions. Perhaps these elements should be considered as specialized forms of 51VC. These elements will also need to comply with PRC-025 LVRT criteria. 9) In reference to Option 17: 150% of the maximum transformer rating can be 250% of the base rating. Transformers are not rated to carry 250% continuously.
No
Implementation should be aligned with other similar standards, such as PRC-024, or even extended based on the number of simulations and relay replacements that will be required.
Group
Operational Compliance
Ed Croft
Yes
As long as Guidelines & Technical Basis is included with the standard, so that the phrase "while maintaining reliable protection" is clarified.
Yes
Yes

We agree with the Implementation Plan of 48 months, but might like to see this time period broken into smaller phases.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Agree
NAGF (North American Generator Forum) In addition to these, we offer the following comments: Question 1: No; 1. It will not always be possible to set load-responsive relays according to Attachment 1 criteria without compromising equipment protection. Where this is the case, the standard must allow for technical exceptions. 2. It should be made clear that entities not using the relay types in Table 1 are by default in compliance with the requirement in R1. 3. Similar to #2 above, if the entity has Device 21 phase distance relays that have load encroachment logic that removes the possibility of tripping on load, the standard should provide an exemption for R1. 4. Measure M1 should be re-written to improve clarity. We suggest, "… each GO shall have: 1) dated documentation of applicable settings calculations, and 2) dated documentation of the settings above having been applied in the field. Question 2: Yes Question 3: No; 1. The criteria for Device 21 on synchronous generators could be greatly simplified by using the criteria in IEEE C37.102, i.e. the 21 setting must be less than or equal to the impedance corresponding to 200% of the generator MVA rating at the rated power factor angle, or a modified version of this to accommodate lower system voltages. 2. The multiple descriptions under "Bus Voltage" (see options 1-3, 5-7, etc) cause this criteria to be difficult to understand and to apply. It is not readily apparent what the different Bus Voltage options are attempting to accomplish. Are options 1 and 2 identical except for the voltage magnitude? It is not clear why a voltage of 0.95 pu is referenced in Option 1 when the Guidelines and Technical Basis section states that the criteria in Table 1 is based on 0.85 pu transmission voltage. Also, the terms "transformer turns ratio and impedance" are not clear as to the intent, and perhaps should be deleted. In the references to "simulation" in options 3, 7, and 15, what specific types of analytical studies are intended here, and what specific generator models are required for them? For these reasons, an approach that is simpler to apply is needed for Table 1. 3. There is a need for a good detailed example calculation for the various options in Table 1. 4. It may be better to break up Table 1 into separate Tables for Generator, GSU's, and Auxiliary Transformers. 5. In Attachment 1, 2nd paragraph: a. Replace "Synchronous generator output pickup setting criteria values " with "Synchronous generator relay setting criteria values" b. We suggest that the setting criteria be based simply on the generator MVA capability and rated power factor, instead of calculating it using the real power rating in MW. 6. Some of the terms may be misunderstood and should be clarified. "Generator Bus" is at the terminals of the generator. Suggest using a term such as "System Bus" or "Transmission Bus" or similar to designate the bus to which the GSU transformer high-side terminals are connected to. Question 4: No; 48 months may be achievable for utility generation, but perhaps not for merchant plans. A timeframe of 72 months is suggested.
Individual
Don Schmit
Nebraska Public Power District
No
1) Table 1, Option 1. "Generator bus voltage corresponding to .95 pu of the high side nominal voltage times the turns ratio of the generator step-up transformer". For example, one of our plants GSU has a high side of 345kv nominal and has a generator nominal voltage of 23kv. Do we assume 345kv/23kv = 15 ratio or do they use the actual ratio which has a tap of 345 and tap of 23.4 = 14.74 ratio. One Generator voltage could be 0.95 x 345 / 15 = 21.85 kv or the Generator voltage could be 0.95 x 345 / 14.74 = 22.24kv. Do we use the Generator bus voltage of 21.85kv, 22.24kv, or is the calculation wrong. If this can be clarified or an example provided this would be helpful. 2) Table 1, Option 1. "The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output – 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output – a value that equates to 150% of rated MW. Can you give an example calculation. Our unit is a 757MVA unit. Lets assume our maximum Seasonal gross MW is 650MW. i. Real Power is 650MW ii. Reactive Power is 975MVAR iii. MVA = 1.15 x SQRT (650 x 650 + 975 x 975) = 1348 MVA at 56 degrees. Do we find the impedance of this MVA value at 56 degrees and the 0.95 bus voltage? If this can be clarified or an example provided this would be helpful. The KD 21 relay is a 75 degree relay so how do we account for the power factor of the relay, power factor of load, and power factor from the MVA with your table. Can you give an example calculation? 3)Table 1, Option 10. Can you give an example calculation for option 10. How is an overcurrent affected by voltage? For a 757MVA, 23KV the FLA is 19,002 amps. Can you give an example for setting the 51 relay. Do we calculate the MVA as shown in step 2.iii above then use the 0.85 x (345 / 15) or 0.85 x (345 / 14.74) to obtain the generator voltage so we can calculate the current once the MVA is known. Why are we not selecting 1.5 x FLA. The FLA does not change based on per unit voltage. If this can be clarified or an example provided this would be helpful.

We have seen many interpretations of the calculations for Table 1 during industry forums. Examples need to be provided.
Group
Tennessee Valley Authority
DeWayne Scott
No
Recommend for clarity revising R1 to read: “. . . . . on each load-responsive protective relay (add language: according to its application to maintain) (remove language: while maintaining) reliable protection. . . . . .” If “Rationale for R1” third bullet, term “while maintaining reliable protection” is to be retained, then recommend this term be incorporated into the “Definitions of Terms Used in Standard” on page 2 of 22, of this draft standard package.
No
The Standard Drafting Team needs to revisit this question. Reviewing the PRC-025-1 SAR, Attachment 1, Order No 733 - Action Plan and Timetable, paragraph 102 is not listed as a significant paragraph of Order 733, or for this standard. FERC Order 733, p102, is a comment from Entergy. Reviewing supporting PRC-025-01 background information on the NERC website, there is no reference to FERC Order 733, p102. This question needs to be re-asked with correct FERC Order references.
No
It is not clear if it is required for 1 type (21, 51V, 51C, or 51) to be set according to Table 1 or each type.
No
Recommend a schedule that will coincide with the protective relay requirements stated in the revised NERC, PRC-005-2, Protection System Maintenance standard. The protective relays requirements within PRC-025-1 should coincide with PRC-005 in order to maximize benefit of maintenance to satisfy these two standards and to minimize resources necessary to perform the relay settings calculations and installations required by PRC-025-1, if the relay settings need to be revised from current PRC-005 settings. Recommend both implementation plans should be a minimum of 72 months.
1. There is a strong relationship between this reliability standard, PRC-025-1, Generator Relay Loadability, and PRC-005-2, Protection System Maintenance, regarding the testing, maintenance, and installing the settings on the same protective system relays. To ensure PRC-025 and PRC-005 are in sync with each other, recommend each be referenced in the “F. Associated Documents” of the other. 2. Recommend PRC-025-1 relay settings be recalculated at a frequency that coincides with PRC-005-2, Protection System Maintenance, performance frequencies found in the PRC-005-2, respective tables. The standard should also allow the generator owner to determine for their own applications whether the on-going repetitive calibrations and functional testing should be time based, performance based, or a combination of the two, in accordance with PRC-005-2.
Individual
Scott Berry
Indiana Municipal Power Agency
Yes
No
IMPA recommends using a phased-in Implementation Plan. Generator Owners will have to review current settings and based on this analysis they may have to replace some relays and/or coordinate these relay settings with their Transmission Owner. If relay replacement is required, Generator Owners will have to budget for the new relays. If settings need to be changed, the Generator Owner(s) will need to verify relay settings with the Generator Manufacturer to ensure there are no warranty/safety concerns associated with the relay setting changes. IMPA recommends a 50% completion in 48 months and a 100% completion in 72 months.
Individual
Patrick Brown
Essential Power, LLC

1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, "while maintaining reliable protection," aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. Additionally, it is not unusual for base loaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future, as declining power prices may cause once-base loaded units to sink into a semi-peaking mode of operation. 2. The currently "To be determined" VSLs would need to be defined before an affirmative ballot could be cast. 3. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavolt ampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavolt ampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnect studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. 4. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from year to year depending on equipment condition and how hard it is pushed. 5. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "…a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." Consequently, the step-by-step calculations can take different paths. Our understanding of what Option 5 requires for example is presented below: a. A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. b. The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. c. The associated MVA at 0.90 PF is 727.778, and the current is 727,778/ (18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set under the TO's direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. d. Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT (655^2 + 982.5^2) or 1180.818 MVA. e. The current is 1,180,818/ (0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals, ref. "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio" under the "Generator Bus Voltage" column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7% overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. 6. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether or not our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term overheating considerations ("field forcing is limited by the field winding thermal withstand capability") may not be correct, however. Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above, and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new requirements. This is not a minor concern. In addition to the thermal damage posed in some cases by PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. This objection gains force from FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. That is, PRC-025 imposes a

worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an extreme requirement is applicable, imposing substantial burden with no identifiable benefit for perhaps 80% of all NERC-registered units. An exception should be made similar to the one proposed in some of the recent generator verification standards, such as, "Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer's advisory." Retrofits could then be pursued only if and where the Planning Coordinator's simulations of Disturbances indicate that a genuine justification exists. 7. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. 8. PRC-025 appears to prohibit loadability relays from having multiple definite-time set points or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of comment #5 above, dual ANSI C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). Such an approach to loadability settings would degrade rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "…while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand; however, the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding, nor is it evident why existing protection schemes that are effective and appropriate should be banned. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. GOs are thus being asked to sign a blank check. We suggest that NERC instead put this standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action. 9. The meaning of the word "overall" is unclear in Applicability paragraph 3.2.3, "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." It should be replaced by the term "generator bus or high side-to-medium voltage," as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. 10. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. 11. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. 12. Regarding voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be as high as specified in the draft standard. 13. Using the term "apply settings" rather than "install settings" in Requirement R1 better suits the accepted terminology for setting the protective device parameters. 14. The phrase "while maintaining reliable protection" in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with "achieving …desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, the desired protection level is more conservative so that generation equipment is not allowed to operate in overloaded conditions. Experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specified in Table 1 and not result in undesirable nuisance tripping. 15. The suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18 causes concern. Suggesting that an entity's existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing (more conservative) philosophy of protection used by many companies has proven (over multiple decades) to be adequate for

protecting equipment and providing reliable power supply to customers.
Individual
Anthony Jablonski
ReliabiltiyFirst
Yes
No
The criteria are much more restrictive than that of the IEEE C37.102 recommendations. As the guide states in regards to a general distance setting of 150 to 200% of the generator MVA rating, "However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." Some of the options for phase distance protection may severely restrict the remote backup protection from the generator. The criteria may prevent the generator backup protection from seeing uncleared faults on the remote ends of lines connected to the plant. It is also not clear whether load encroachment methods would work as referenced in the guidelines since the angle of power flow may be near 60 degrees. Load encroachment at these high angles would cut out most of the reach characteristic and allow little margin for detecting arcing.
Yes
Yes
Individual
Kirit Shah
Ameren
No
(1) As written R1 can be read to require the GO to use load-responsive protective relays. The wording of the first sentence in Attachment 1 is clearer. Please insert "that applies load-responsive protective relays" in R1. "Each Generator Owner that applies load-responsive protective relays shall install settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection." (2) In the Rationale for R1 please insert this as the second sentence in the third paragraph "Equipment protection takes precedence over loadability, but must be clearly justified if the loadability options in Attachment 1 are not met." These generators are quite valuable and have long repair times so their protection must not be compromised. In its generator protection webinars, NERC emphasized that damaging a generator would harm BES reliability more than tripping on load. Though not exactly comparable, it's clear that restoration time is longer when equipment is damaged (e.g. Hurricane Sandy) than from a blackout (e.g. AZ-CA).
No
(1) We have reviewed in detail our own and SERC-wide performance for the last 6 years, and have not had a single generator protection Misoperation because of relay loadability (for Ameren we cannot recall such an operation in the last 30 years.) It appears that the SDT relies too much on the 2003 blackout single event and empirical data for its justification. While we agree it is desirable to protect the generator and meet the loadability objective, protection equipment changes and/or additions are not justified. (2) Please state the total number of generators that tripped in the 2003 blackout to provide proper context. Also, did 2003 blackout post mortem simulations show that had these 28 generators (8 tripped by phase distance and 20 tripped by overcurrent) ridden through the event, the blackout would have been avoided or significantly smaller?
No
(1) The first sentence implies that only "one" of the 17 Options needs to be met. Actually Option 17 almost always must be met as well as one of the first 16 Options. In cases using different relay types for the generator two of the first 16 Options need to be met. (2) Our reading is that the 115% is applied to the loading criteria prior to calculating the impedance or current Pickup Setting Criteria. An example for Options 2 and 5 would provide clarity and help reach your loadability objectives without trapping the GO into unintended non-compliance. (3) Our reading is that Bus Voltage instructions for Option 1 ignore the IZ voltage rise through the GSU but include it for Option 2. Is that the SDT's intention? (4) The last part of p 7 paragraph 2 states the Reactive Power capability is calculated at rated power factor (typically 0.8 to 0.9) which conflicts with the Table 1 Pickup Setting Criteria which uses Reactive Power equal to 150% of rated MW. We suggest to correct this discrepancy. (5) PRC-023 provides a wider range of criteria for meeting transmission loadability. (6) An entity may be forced to reduce the Real Power capability it reports to the Planning Coordinator in order to meet the standard as proposed. This would have an adverse impact on BES reliability.

No
Please allow 60 months to implement if indeed protection system equipment or schemes must be changed to comply with R1. More than 48 months will regularly be needed to budget, design, procure materials, obtain construction outages, install and commission such protection system equipment changes.
Yes. (1) Applicability should be consistent with PRC-023-2 (generators connected at 200kV and above, etc.). (2) System connected auxiliary transformers should be excluded. This is consistent with the industry's determination in PRC-005-2, which has now passed recirculation ballot. (3) VSLs are listed as 'to be determined'. We recommend that severity be risk-based by relating it to the % of MWh the generator in violation has provided during the period of violation (i.e. % of GO entity's total MWh production.)
Group
Bonneville Power Administration
Jamison Dye
Yes
Individual
Don Jones
Texas Reliability Entity
Yes
No
TRE suggests the following changes for Attachment 1: Relay Settings, Table 1: a) On page 7 under 'PRC-025-1-Attachment 1: Relay Settings' discussion of the synchronous generator reactive capability calculations is confusing. TRE suggests the following language for Paragraph 2: "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined based on the unit's nameplate megavoltampere (MVA) and the calculated rated MW at the unit's rated power factor." b) In the Table 1. Relay Loadability Evaluation Criteria; recommend specifying 'Synchronous generator bus terminal' instead of 'Synchronous generators' in the application column for Options 1, 2, 3, 5, 6 & 7. c) In the Table 1 - Bus Voltage column, clarify that the generator bus voltage calculation needs to include the generator step-up transformer winding tap setting (NLTC or LTC tap settings) in the turns ratio calculation of the generator step-up transformer, when applicable. Suggested language, "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer. The turns ratio calculation of the step-up transformer must include the transformer's NLTC or LTC tap settings implemented in operation." d) In the Table 1 – Pickup Setting Criteria column, clarify that the rated power factor must be used to calculate the impedance value. Recommend adding the following note under the setting criteria; "Generator rated power factor shall be used to calculate the impedance value". e) In the Table 1 Option 3- Pickup Setting Criteria column, the Reactive Power output determined by the simulation is typically based on the voltage set point at the controlled bus. This can be a moving target if the simulations are done based on different loading conditions. TRE suggests using the generator reactive capability curve (D-Curve) or the actual reactive test data to determine the generator maximum Mvar capability that is to be used for the impedance calculation. f) In the Table 1 -The Phase Time Overcurrent Relay (51V) voltage-restrained option does not provide specific voltage restraint slope settings to be used. For consistency purpose, voltage restraint slope settings should be included in the pickup setting criteria. g) TRE recommends including generic D-curve, R-X diagrams, voltage-restrained relay curve, and other overcurrent, voltage controlled relay curves in this standard to provide additional clarification.
No
TRE thinks that the implementation plan is too long and we suggest 24 months.
Group
Luminant
Brenda Hampton
No

Luminant recommends: 1. The phrase "Each Generator Owner shall install …" be revised "Each Generator Owner shall set …". The Generator Owner would only be required to show compliance with the documentation of setting calculations and not required to show a recent test report. 2. The corresponding measure would be revised to read, "The Generator owner shall have evidence such as spreadsheets or summaries of calculations to show that each generator load responsive relay is set according to R1." These recommendations would maintain consistency of requirements and measures with the approach used in PRC-023-2 (Transmission Loadability standard).
No
Luminant agrees that a reasonable approach was used to define limits based on unit MVA ratings for relays susceptible to load. However, the drafting team does not address the coordination of the relay with transmission relaying as described in FERC Order 733, paragraph 107. The Commission directed the ERO to address relay loadability that facilitates the reliability goal of ensuring coordination between transmission and generator protection systems, as required by PRC-001 (draft standard PRC-027). Luminant recommends adding Transmission Owners to the Applicability Section and include relay coordination with the Transmission Owner for each applicable load responsive relay as a separate requirement and measure.
No
1. Luminant agrees that although Table 1 in Attachment 1 clearly identifies criteria for setting load responsive relays, it is recommended that the drafting team add information in the Attachment that describes the bus voltage conditions as steady state values only and does not consider relay operations for fault conditions. In addition, a statement that the Generation Owner must coordinate relays with applicable AVR response and transmission relaying. 2. Luminant recommends the "Pickup Setting Criteria" column for real power output be revised to "100% of maximum seasonal gross or maximum continuous rating of the turbine reported to the Planning Coordinator". 3. In Row 17 (Auxiliary Transformers - Phase Overcurrent Relay), Luminant recommends that the 150% pickup setting criteria be applicable to the relay regardless of its electrical location (high or low side of the UAT).
Yes