**Individual or group. (56 Responses)**
**Name (34 Responses)**
**Organization (34 Responses)**
**Group Name (22 Responses)**
**Lead Contact (22 Responses)**
**Contact Organization (22 Responses)**
**Question 1 (51 Responses)**
**Question 1 Comments (56 Responses)**
**Question 2 (49 Responses)**
**Question 2 Comments (56 Responses)**
**Question 3 (50 Responses)**
**Question 3 Comments (56 Responses)**
**Question 4 (0 Responses)**
**Question 4 Comments (56 Responses)**
**Question 5 (41 Responses)**
**Question 5 Comments (56 Responses)**
**Question 6 (41 Responses)**
**Question 6 Comments (56 Responses)**
**Question 7 (43 Responses)**
**Question 7 Comments (56 Responses)**
**Question 8 (0 Responses)**
**Question 8 Comments (56 Responses)**
**Question 9 (43 Responses)**
**Question 9 Comments (56 Responses)**
**Question 10 (39 Responses)**
**Question 10 Comments (56 Responses)**
**Question 11 (0 Responses)**
**Question 11 Comments (56 Responses)**

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| Group |
| Pepco Holdings Inc and Affiliates |
| David Thorne |
| Pepco Holdings Inc. |
| No comment |
| No |
| Agree with the generating unit nameplate thresholds as defined in this standard and the compliance registry, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and |

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| (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition. Of course, Synchronous condensers are not spelled out either in the Compliance Registry, or the BES definition, and therefore they will have to be addresses separately in 4.2.2 as “Individual Synchronous Condensers greater than 20MVA (gross nameplate rating) directly connected at the point of interconnection at 100kV or above. “ |
| No comment |
| No comment |
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| |
| Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds |

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| in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition. |
| No |
| Same comments as in Question 2. |
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| |
| Group |
| Northeast Power Coordinating Council |
| Guy Zito |
| Northeast Power Coordinating Council |
| No |
| Attachment 1 requires a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% that is expected to last more than 6 months within 12 months. This is an excessive period of time for a generator to be providing less than expected Real or Reactive power output. Also, Attachment 1 requires staged verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.). • The data requested in this Standard will verify a generator’s capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data for both under-excited and over-excited field conditions will result in 4 specific data points that can assist TP’s in system studies. The GO can obtain this data by planning on doing the maximum lagging and leading tests when system conditions allow to measure the 4 specific data points desired. • “Separate tests” are not explained except for the statement “separate testing is allowed for this standard” which is in Attachment 1. What constitutes “separate testing”? |
| No |
| The data requested in this Standard will verify a generator’s capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, synchronous condensers should be removed from MOD-025. |
| No |
| The Reliability Coordinator is the entity that should receive this data. There are instances where a number of entities are registered as Transmission Planners. To avoid confusion this data should be submitted to a single entity who will then |

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| distribute the data. Transmission Planner should be added to the Applicability Section 4.1 Functional Entities. |
| This testing will be difficult to stage due to the four point reactive power testing. The power system may have to be reconfigured in many cases to allow for the changes in generator reactive power output, and the testing may not be able to be carried out when planned. System disturbances can occur that will disrupt the testing. For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are “on-line”. For reactive testing, this would be better stated as 90% of the plant’s available capability considering that some wind turbines may be able to produce/absorb reactive power with no real power production. Does “on-line” just imply that the wind turbine breaker is closed and no requirement for real power production? In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power connected at the high-side of the generator step-up transformer (point D), and Aux or Station Service Real Power connected at other points of interconnection (point E). Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)? The data requested in this Standard will verify a generator’s capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies (and not include synchronous condensers). Therefore, the Purpose Statement be edited to read: • “To assure accurate information on generator gross and net Real and Reactive Power capability Reactive Power capability is available for planning models used to assess BES reliability.” The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime, unless the generator has been rewound, cooling systems modified, installation of a new exciter, etc. Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? A GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. 2. Comments on Attachments 1 and 2: • The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. • Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. • Notes 1 – 4 at the end of Attachment 1 should be removed from the Standard and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. • Section 4.2.1 (and elsewhere): the term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability Sections is confusing. |
| No |
| The footnote regarding partial load rejection testing is footnote 4, not 5. The |

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| footnote should be removed and the language in 2.1.1 be revised. • 2.1.1 Documentation comparing the applicable unit's model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled. |
| Yes |
| |
| No |
| Base loaded units could provide governor response for over-frequency events and should have verified models for this event. The term "base loaded" is not defined in MOD-027. |
| Some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical. The intent and goal of the SDT and MOD-027 are to achieve more accurate system modeling, and are to be supported. Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this what is intended? R2: There is linkage between the parenthetical "(within 365 calendar days from the date that the response was recorded)" and the reference in 2.2.1 "…unit's model response to the recorded response for either….", but this language is not clear. The term "response" in the parenthetical needs to be clarified. R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. Recommend the following wording to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc.), and any protection system controls (i.e. emission control systems on combustion turbines, etc.) effects of outer loop controls (such as operator set point |

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| controls, and load control but excluding AGC control) that override the governor response (including blocked or non-functioning governors or modes of operation that limit the frequency response) if applicable. R3: First bullet, term “usable” should be revised to “usable as defined in Requirement 5”. Note that R5.1, 5.2 and 5.3 clearly define the criteria for “usable”. Section G References: Delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard. |
| No |
| This Standard is applicable to generating units/facilities that meet the compliance registry criteria. However, this Standard is not applicable to any type of synchronous condensers. The purpose for synchronous condensers is to provide voltage support as needed, similar in function to a capacitor bank or shunt reactor. |
| Yes |
| |
| This Standard is written to verify coordination of generating unit Facility or synchronous voltage regulator controls, limit functions, equipment capabilities and Protection Systems. The Standard, as written, may apply to more generation than intended. The Standard as currently written protects the BPS and applies to generation units that are required to register with NERC in accordance with the Statement of Compliance Registry Criteria (SCRC). The approval of a new BES definition by FERC will define new more limiting inclusion criteria than the (SCRC) for generators and therefore will change the population of generators material to the BES. The unintended consequence is that the current wording of the Standard protects the BPS not the BES and uses the SCRC for defining applicable generators, not the BES definition generator Inclusion Criteria. The Standard in its current form will apply to generators that will not be considered material to the BES and not necessary for the reliability of the Transmission System. Section 4.2.1: term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the NERC defined term. |
| Group |
| Southwest Power Pool Standards Development Team |
| Jonathan Hayes |
| Southwest Power Pool |
| Yes |
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| Yes |
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| Yes |
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| Yes |
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| Yes |
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| Yes |
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| Yes |
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| Yes |
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| |
| Individual |
| Chris de Graffenried |
| Consolidated Edison Co. of NY, Inc. |
| No |
| • The data requested in this Standard will verify a generators capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data both under and over excited field conditions will result in 4 specific data points that can assist TP's in system studies. For example, the GO can obtain this data by: o The maximum lagging and then leading test at full load may be performed during a high load day to obtain two data points. o The maximum lagging and then leading test at minimum load may be performed during the evening to two data points. • We could not find a paragraph explaining separate tests except for the statement "separate testing is allowed for this standard". So no, we don't agree with this revision. Attachment 1 requires verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.). |
| No |
| The data requested in this Standard will verify a generators capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, we recommend that synchronous condensers be removed from MOD-025. |
| Yes |
| Please add the TP in the Functional Entities in section 4.1. |
| Comments: 1. The data requested in this Standard will verify a generators capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies. Therefore, we recommend that the Purpose Statement be edited should read - • "To assure |

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| accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BES reliability.” • The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime, unless the generator has been rewound, cooling systems modified, new exciter, etc. • Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. Is this the SDT’s understanding? 2. Comments on Attachments 1 and 2: • The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. • Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. • Notes 1 – 4 at the end of Attachment 1 should be removed from the Standard and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. • Section 4.2.1: term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. |
| No |
| We believe the footnote regarding partial load rejection testing is footnote 4, not 5. We recommend the footnote be removed and the language in 2.1.1 be revised. 2.1.1: This requirement needs additional clarity. In one sentence, 2 on-line options and 1 off-line testing option have been proposed that compare the actual response to the model response. We recommend the following edits which provide more clarity and eliminate Footnote 4. • 2.1.1 Documentation comparing the applicable unit’s model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled. |
| |
| No |
| The term “base loaded” is not defined in MOD-027. |
| Comments: Yes • Con Edison strongly supports the intent and goal of MOD-027 and the SDT efforts to achieve more accurate system modeling. • Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. • Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should |

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| be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. • Section 4.2.1: term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. • Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance. We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this the SDT’s understanding? • R2: we believe that there is linkage between the parenthetical “(within 365 calendar days from the date that the response was recorded)” and the reference in 2.2.1 “…unit’s model response to the recorded response for either….”, but this language is not clear. The SDT is encouraged to clarify what the term “response” in the parenthetical is referring to. • R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. We recommend the following verbiage to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc) and any protection system controls (i.e. emission control systems on combustion turbines, etc) [delete: effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that override the governor response (including blocked or nonfunctioning governors or modes of operation that limit] the frequency response if applicable. • R3: first bullet, term “usable” should be revised to “usable as defined in Requirement 5”. Note that R5.1, 5.2 and 5.3 clearly define the criteria for “usable”. • Section G References: delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard. |
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| |
| • Section 4.2.1: term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the NERC defined term. |
| Individual |
| Brenda Hampton |
| Luminant Energy Company LLC |
| Yes |
| |
| Yes |
| |
| Yes |
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| Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power |

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| capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section 3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2). On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope. Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the simplified one-line diagram …" Generator Owners can fill in the appropriate quantities at locations A-F. As an example, on some units values would be input for A, B, and F and NA entered for C, D, and E. For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard. |
| Yes |
| |
| Yes |
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| No |
| Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and include the exemption that excludes units that are base loaded. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3). |
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| Yes |
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| No |
| Luminant disagrees with the need to illustrate coordination of the phase distance |

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| relay with AVR controls. The sample R-X diagram does not indicate how the relay is coordinated with field forcing capability. Since this function is covered in the generator loadability standard currently under development, Luminant recommends that this function be removed from the R-X diagram. |
| Luminant recommends in Requirement R1 that the coordination with Protection System be modified to reference the “applicable Protection System devices as referenced in Section G”. As written, Protection System is all inclusive and would require verification of settings beyond the scope of this standard. |
| Individual |
| Dan Roethemeyer |
| Dynegy |
| Yes |
| |
| Yes |
| |
| Yes |
| |
| No |
| Yes |
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| Yes |
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| No |
| We don't understand the question. The two sentences seem to contradict themselves. |
| The division of responsibility (between GO and TP) in the task of ‘verifying’ the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and ‘verify’ the models. This would also eliminate the question of what constitutes a ‘verified’ model, i.e., how good is good enough. |
| Yes |
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| Yes |
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| No |
| Individual |
| RoLynda Shumpert |
| South Carolina Electric and Gas |
| Yes |
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| Yes |
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| Yes |
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| Sections 4.2.1, 4.2.2, 4.2.3 uses the term "bulk power system." should this be changed to "Bulk Electric System." Attachment I, "Verification specifications for applicable Facilities", #2. The third sentence should be revised to read "... at least 50 percent of the REACTIVE capability ..." Also, in the VSL section: R1, Moderate VSL should read "34 to 66 percent of the data." R1, R2, R3 Severe VSL should read "greater than 15 calendar months." |
| Yes |
| The footnotes in the redline and clean versions of MOD-027-1 have different numbering. |
| Yes |
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| Yes |
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| Yes |
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| Yes |
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| |
| Individual |
| Martin Kaufman |
| ExxonMobil Research and Engineering |
| Yes |
| |
| No |
| The SDT should clarify that a Synchronous Condenser is not a Synchronous Motor. Synchronous condensers are operated to provide Voltage Support to the bulk electric system through the production of VARS. A Synchronous Motor is theoretically the same piece of equipment with one exception; in a modern industrial electric distribution system, a Synchronous Motor’s purpose is to drive a mechanical load while remaining VAR neutral (or closes to it). As written, industrial facilities that are registered as Generator Owners and operate large Synchronous Motors may be required to comply with this standard and be unable to comply with this standard due to the nature of the equipment that operates the Synchronous Motor’s excitation system. |
| Yes |
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| Yes |

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| No |
| A model’s validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit’s response. |
| Yes |
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| |
| No |
| : A model’s validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit’s response. |
| Yes |
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| Group |
| Tennessee Valley Authority - GO/GOP |
| David Thompson |
| NERC Reliability & Assessments |
| Yes |
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| Yes |
| |
| Yes |
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| Testing a unit to the limits of its’ protective function (such as overvoltage) creates the possibility for an unplanned unit trip. The SERC Regional Criteria for MOD-024 and MOD-025 allows an engineering assessment in conjunction with operational data review as a valid verification method. MOD-025-2 should include an engineering assessment as a valid method of verification. |
| Yes |
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| Yes |
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| Yes |

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| Some consideration should be given for sister units if it can be demonstrated that the governor controls have identical settings. The 5% capacity factor threshold may be lower than necessary. Consider at least a 10% threshold since units which operate that infrequently are unlikely to be on line when a BES event occurs. |
| No |
| The MVA criteria included in MOD-026-1 and MOD-027-1 are more appropriate for this standard than the 20 MVA criteria presently used. A 20 MVA unit is not critical enough to the BES reliability to justify this level of documentation of coordination. Standard PRC-004 already requires an investigation into relay misoperations for units greater than 20 MVA which would be the result of coordination issues. |
| Yes |
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| Individual |
| Andrew Z. Pusztai |
| American Transmission Company, LLC |
| Yes |
| |
| Yes |
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| Yes |
| |
| Please consider the following comments: Attachment 1, Periodicity for new verification Item 3 – Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, “. . . or mutually agreed verification date.” Attachment 1, Verification Specifications Item 2.1 - There appears to be a typographical error near the end of Item 2.1, we believe that it should state, “Retest the facility within six months of being unable to reach the 90 percent threshold”. Attachment 1, Verification Specifications, Item 4.1, Note 1 – Consider deleting the last sentence because it contradicts the purpose of the standard, contracts the sentiment of Note 2, and will likely to be untrue after verified values are entered into the Transmission Planner’s database and are submitted according to MOD-010. |
| Yes |
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| Yes |
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| Yes |
| ATC agrees with the exception for base load units, however, recommends adding text that explicitly highlights that the second to last item in “Event Triggering Verification” column refers to base loaded units such as, “New or existing base loaded units that are normally not responsive to a frequency excursion event”. |

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| Please consider the following comments: 1. Applicability, 4.2.1, bullet 1 – As a Transmission Planner, ATC recommends that the unit size value be “20 MVA” rather than “100 MVA” and the aggregate plant size value be “75 MVA” rather than 100 MVA” to agree with the NERC Compliance Registry Criteria, which implies that the 20 MVA unit size and 75 MVA plant size values are large enough to be subject to the Reliability Standards. We are not aware of a definitive study that found the 100 MVA value to be appropriate for the Eastern Interconnection, particularly the upper Midwest portion of the system. 2. In Requirements, R1, bullet 2 –ATC recommends to change the wording to, “obtain dynamic turbine/governor, load control, and active power/frequency control model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations”. Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. Requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets, depending on the Generator Owner licenses or lack of licenses. |
| Yes |
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| Yes |
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| Group |
| Arizona Public Service Company |
| Janet Smith |
| Arizona Public Service Company Regulatory Compliance |
| Yes |
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| Yes |
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| Yes |
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| Need for real power verification and reliability benefits are not clear. Similarly need for and reliability benefits of all the detailed calculations are not clear. The drafting team should poll the industry as to the reliability benefits and determine out who will use the information and what is the benefit of such detailed reporting. |
| Yes |
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| Yes |
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| Yes |
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| Individual |
| Michelle R D'Antuono |
| Ingleside Cogeneration LP |
| Yes |
| Even if the requirements are somewhat redundant, there are a number of important differences between Real and Reactive Power validations. In addition, there is a need to allow Generator Owners to address each separately if they should so choose. For example, a Real Power validation may be easily handled through actual operations data, while Reactive Power validations may need coordinated testing with the interconnected Transmission Operator. Under a single requirement, there is a risk that Compliance Authorities will assume that every test must be performed at the same time – using the same method. |
| No |
| Ingleside Cogeneration LP believes that MOD-025-2 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System – and this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of the BES takes effect. |
| Yes |
| Ingleside Cogeneration LP agrees that the proper recipient is the Transmission Planner. There is no reliability reason that we are aware of to include Transmission Owner in the loop – as the previous version of MOD-025-2 called for. |
| Ingleside Cogeneration LP is concerned that there is no apparent provision in MOD-025-2 should a restriction in the extent of Reactive Power validation testing be placed upon the GO or TO by the Transmission Operator. In many cases, the TOP cannot allow the local system to operate beyond a certain Power Factor – especially when the system is supplying reactive power to the generator (leading). It may be the project team's intent that such a limitation is expected to be captured as a "Remark" in the reporting template (Attachment 2). However, we believe that the requirements must include allowable exceptions – as that is what Compliance Authorities will use to assess compliance. Secondly, Measure 1 calls for a Generator Owner to provide correction factors for ambient conditions within 90 days of a request from the Transmission Planner. We agree with the reliability need, but believe there should be corresponding enforceable language in the requirement. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-025-2, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise |

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| can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 “Definition of the Bulk Electric System” which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities. |
| Yes |
| Ingleside Cogeneration LP agrees that there must be viable options available in the event that a frequency excursion of the appropriate magnitude was not captured during the validation time frame. This may be more applicable to smaller generation facilities, or those which have a small capacity factor and are rarely online. We also agree that some further analysis may be required to account for the difference in operating conditions as described in the footnote. |
| Yes |
| We support the efforts by all project teams to clearly define the implementation and subsequent periodic evaluation time frames – as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC’s Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-027-1, we believe that the proposed intervals are sufficient to perform the frequency performance model validations; however they are initiated. |
| No |
| Although Ingleside Cogeneration LP agrees with the concept that a base load unit does not need to be verified, it is not sufficient to capture this exception only in Attachment 1 of MOD-027-1. Similar to the exclusions for units with very low capacity factors, the Applicability section must also clearly identify that base loaded units are not subject to MOD-027-1. |
| We agree with the SDT’s position that 80% of generation capacity in each Interconnection should be targeted for validation – not the 100% that some regulatory bodies might prefer. There is a careful balance between the costs to perform the validation and the expected reliability benefit which we expect to gain. We must look for cheaper alternatives for those generators which have a negligible impact on BES performance or serve non-critical load. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-027-1, which references generation connected to the “bulk power system” rather than the NERC-defined term “Bulk Electric System”. This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 “Definition of the Bulk Electric System” which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities. |
| No |
| Ingleside Cogeneration LP has not changed its position that PRC-019-1 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System – and |

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| this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of the BES takes effect. |
| Yes |
| We agree that it is appropriate to add a statement to the P-Q and R-X diagrams that they show performance at nominal voltage and frequency levels. We also agree that the SSSL calculation should be based upon a fixed field current value, even if it does not take into account the action of the AVR in automatic mode. It is a far less complex method to use and returns a more conservative value in any case. Ingleside Cogeneration would like to commend the SDT's for holding to its position that there is no need to complicate the analysis by assessing performance under transient conditions or single contingency scenarios. In our view, there is no justification to adding time and effort to an initiative until data shows that it will result in a tangible reliability benefit. |
| We believe that the project team has taken a positive step in R1.1.1 to establish that Protection Systems must operate before the generator or synchronous condenser sustains damage. This may actually be more sensitive than the SSSL – which is a good, but not perfect, proxy for the point at which components may be harmed. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of PRC-019-1, which references generation connected to the "bulk power system" rather than the NERC-defined term "Bulk Electric System". This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 "Definition of the Bulk Electric System" which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 – which was issued to eliminate exactly these kinds of ambiguities. |
| Individual |
| Michael Falvo |
| Independent Electricity System Operator |
| Yes |
| |
| Yes |
| |
| Yes |
| |
| There is a typo on Row E in Attachment 2: The word "yransformers" should read "transformer". |
| No |
| Footnote 5 as written contains requirements that are in addition to Part 2.1.1 as opposed to provide clarification or explain the testing process. We suggest that the requirements in Footnote 5 be put into Part 2.1.1 or its sub-part. We also suggest that the language be made clearer, in particular the use of the word "load" in "load rejection", "load or set point control", and "on load" which is very confusing. |

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| Yes |
| We agree with the periodicity requirements. We respectfully point out once again that the periodicity criteria are not guidance, they part of Requirement R2 and must be complied with. |
| Yes |
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| 1. In the Applicability Section, 4.2.1, we agree with the change from a 100kV threshold to an MVA based threshold. However, there does not appear to be any technical justification for the first two bullets, i.e. 100 MVA for individual units directly connected to the bulk power system and generating plant with a total of 100 MVA connecting to the bulk power system at a common bus. Why would the first bullet not be 20 MVA and the second bullet not 75 MVA to be consistent with the registration criteria and the thresholds for generators having to comply with MOD-026 and PRC-019? Similar comments on 4.2.2 first bullet, and 4.2.3 first bullet for WECC and ERCOT, respectively. 2. We continue to disagree with Requirement R5 and it Parts R5.1 to R5.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate turbine/governor and Load control or active power/frequency control model, especially if such devices are new for which there are no previous simulations to benchmark with. Part 5.3 stipulates one of the criteria for deeming a model usable. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable. |
| Yes |
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| Yes |
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| R1 VSL: There is only a SEVERE VSL assigned to Requirement R1, for the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1. This condition does not appear to be consistent with the intent of Requirement R1, which requires the responsible entities to coordinate the voltage regulating system controls, (including In-service limiters and protection functions) with the applicable Facility capabilities and Protection System settings. The parts that follow also prescribe the actions need for verification, not the identification of the existence of the verification |

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| information. Note that the SEVERC VSL for Requirement R2 includes the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years. This condition is almost identical to the SEVERE VSL for R1, except it has a time component associated with the failure. A failure to verify the existence of the coordination specified in Requirement R1 in more than 6 years, despite it might have implemented the verification exercise stipulate din R1, can subject an entity to being found non-compliant twice. We have a serious concern with this. |
| Individual |
| S. Tekala |
| SRP |
| No |
| Real Power tests were performed at the same time as Laod Reactive Power testing in the past and plotted on the generator"s capability curves. What would be gained by conducting two separate tests? |
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| Group |
| SERC Generation Subcommittee |
| David Thompson (Chair) ; Joe Spencer (SERC staff) |
| SERC Reliability Corporation |
| Yes |
| However, see our response to Question #4. |
| No |
| Clarification should be made on applicability. Does this apply only to stand-alone synchronous condensers, or are hydro units, that can be used in condensing mode, also included? Also, we believe that the 20 MVA cut-off rating is too low for this standard. We would suggest that the same threshold used in MOD 26 and 27 (100 MVA), be used. If necessary, the regions can set more restrictive thresholds. |
| Yes |
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| • Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions (if requested), but this is not included in R1, Attachment 1 or Attachment 2. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), |

some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. • Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. • To accomplish the stated goal of Steady State Model Validation, there needs to be clarity in the definitions for model terms. We have developed a draft set of definitions that is available to the SDT. • Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which provided a process where an engineering review (with associated operating data) should be performed first with testing to be done on a limited basis, if needed, to capture data not covered by an operational review. The SDT could leverage this guide to better understand the approach, which was agreed to by the region's planning and generator operators. This approach should be adopted as an additional method to verification. • Testing may be desirable to identify issues, such as incorrect AVR limiter settings, but there are other methods that also would accomplish those goals. If the goal is operational testing to uncover these types of issues, that should be clarified in the purpose of the standard as opposed to the stated goal of model validation. • Attachment 1, Verification specifications for applicable Facilities, Note 1: We recommend revising the last sentence to state, “The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit’s reactive capability for extreme system conditions. See Note 2.” • Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. • The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. • Attachment 2, Summary of Verification – What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. • Applicability Section – change “bulk power system” to “BES”. • Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or “sister” units should be allowed. • Testing a unit to the limits of its protective function (such as overvoltage) creates the possibility for an unplanned unit trip, particularly problematic on nuclear units.

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| No comment |
| No comment |
| No comment |
| No comment |
| No comment |
| No comment |
| No comment |
| Group |
| SERC Dynamic Review Subcommittee (DRS) |
| John O'Connor (chair) ; Joe Spencer (SERC staff) |
| SERC Reliability Corp. |
| Yes |
| |
| No |
| In some cases there is no benefit to require testing of smaller units. The DRS recommends that units with nameplate ratings at or below 100 MVA (consistent with the MOD-027-1) be exempted from testing upon mutual agreement between the GO and Transmission Planner. |
| Yes |
| The Transmission Planner is in the best position to determine the impact of the results on long term system reliability. Additionally, the Transmission Planner is often the entity that provides this data to other entities (via the MMWG process) for modeling and simulation purposes. |
| Yes: • VAR-002-1.1b Requirement R1 states “The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.” However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. The DRS recommends that MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the DRS recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard. • On Attachment 2 Comment Section for Point A, add note that “individual unit values |

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| are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) • On Attachment 1, item 2.6, add sentence stating that “GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.” If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. • On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. • The DRS recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of “sister unit” concept. This will facilitate more consistent unit verifications. • The DRS agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. The DRS recommends that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar changes which impact the reactive testing results. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. |
| No comment |
| No |
| Regarding the terminology in Attachment 1, “Turbine/governor and load control and active power/frequency control”, should all the “and”s in the Event Triggering Verification column be “or”s? The DRS recommends that this be reviewed for consistency. |
| No |
| The DRS sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification. |
| The DRS found the excerpt below (section 4.2.1 bullet 2)to be confusing, particularly the second sub-bullet below: • For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating); and o Each generating plant or generating Facility consisting of |

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| individual generating units less than 20 MVA (gross nameplate ratings Could the SDT provide some examples of how this would work? Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability. |
| No comment |
| No comment |
| There needs to be a requirement that the GO protection coordinate with the steady state stability limit. We recommend inserting “or reach steady state stability limits” after “equipment” in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions. Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? We recommend that you stay with a 30 day increment. Also in R2 you need a space between “5years”. |
| Individual |
| John Seelke |
| Public Service Enterprise Group (PSEG) |
| No |
| In splitting R1 into two requirements, the R2 erroneously refers to “Real Power”; this should be “Reactive Power.” The first sentence in added paragraph Attachment 1 regarding separate testing of Real and Reactive Power testing should be rewritten. The term “Load” as used does not conform to the Glossary definition of “Load,” which is “An end-use device or customer that receives power from the electric system.” The only combined testing on Real and Reactive Power applies to sections 2.1 and 2.2 in Attachment 1 where Real Power is tested. Therefore, the added sentence should be rewritten as follows: “It is intended that Real Power testing in sections 2.1 and 2.2 be performed at the same time as Reactive Power testing; however separate testing is allowed for this standard.” |
| No |
| In the Background material on the Comment form for MOD-026-2 and PRC-024-2, the following statement is included for MOD-026-2: “The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO |

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| Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers." If synchronous condensers are not currently addressed in the NERC Registry Criteria, they should not be included in the either MOD-025-2 or PRC-019-1. |
| No |
| Transmission Operators should also be provided the data. |
| We have the following additional concerns: a. The entire section 4.2 has language that includes "directly connected to the bulk power system." The BES is a subset of the BPS per Order 743, and the GVSDT should consult with the SDT for Project 2010-17 – Definition of BES – to develop alternate language that instead refers to the BES. b. We believe that the addition of section 5.3 (Wind Farm Verification) under the "Effective Date" (section 5 in the standard) is both misplaced and confusing. A paragraph should be written in the "Verification specifications for applicable Facilities" section in Attachment 1 that follows paragraph 1 which would clarify for all generators how the percent verification of applicable Facilities in the "Effective Date" section should be calculated. The following is proposed: "1.1 The percent verification for applicable generating Facilities referenced in the "Effective Date" section of the this standard depends upon how the owner of generating units that are 20 MVA or less and that are part of a plant that is larger than 75 MVA in the aggregate choose to address verification. If the owner verifies the aggregate of all units that are less than 20 MVA as a group, then verification must include all of the aggregate units (i.e., a single applicable facility) taking into account the 90% threshold (which is considered "all") for wind turbines or photovoltaic inverters as provided in paragraph 2.1 below. If the owner verifies each unit that is less than 20 MVA on an individual unit basis, then the percent verification for that plant will be calculated on a unit basis. For example, suppose a plant has 5 units that are 20 MVA or less and 4 units that are greater than 20 MVA at a plant that in aggregate is greater than 75 MVA. If the owner chooses to verify each of the 20 MVA or less units individually, there are 9 applicable Facilities at the plant. If the owner chooses to verify the 5 units that are 20 MVA or less as a group, there are 5 applicable Facilities at the plant – one aggregate "Facility" comprised of 5 units that are 20 MVA plus or less plus 4 units that are greater than 20 MVA." c. We are concerned with the requirements in Attachment 1 to perform tests, especially Reactive Power capability tests, with the automatic voltage regulator in service (paragraph 2 under the "Verification specifications for applicable Facilities" section) while maintaining the Transmission Operator's voltage schedule and Reactive Power output (see VAR-002-1.1b, R2). Unless R2 in VAR-002-1.1b is temporarily waived for staged tests, it may be impossible to meet paragraph 2.1 under the "Verification specifications for applicable Facilities" section in Attachment 1 since adjusting the Reactive Power output to verify leading and lagging power limits at maximum Real Power output may cause a violation of the cited VAR-002-1.1b requirement. MOD-025-1 needs to address this issue. RFC's standard MOD-025-RFC-1 addresses the issue in its Attachment 1, paragraph 1.2, which states: "If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the |

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| Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.” d. Paragraph 2 in Attachment 1’s “Verification specifications for applicable Facilities” section has this statement: “Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve.” What is meant by “50 percent of the capability shown on the associated D-curve”? Since the D-curve shows both Real and Reactive Power, would a previously staged test be acceptable if it demonstrated only 50 percent of the maximum Real Power capability per the generator’s D-Curve? e. In Paragraph 2.1 in Attachment 1’s “Verification specifications for applicable Facilities” section, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. RFC’s standard MOD-025-RFC-1 supports this position, since its Attachment 1 states: “Under-excited (leading) Reactive Power capability verification is not required of nuclear units.” This sentence should be added to Paragraph 2.1 in Attachment 1. f. In paragraph 2.2 in Attachment 1’s “Verification specifications for applicable Facilities” section, the second sentence excludes nuclear units (“Units” is inappropriately capitalized in the standard this paragraph) from being required to perform Reactive Power tests in paragraph 2.2. For clarity, we suggest that “nuclear” be included in the wind and photovoltaic exceptions in the first sentence, and that the second sentence be deleted. Paragraph 2.2 would thus read “Verify Reactive Power capability of all applicable Facilities, other than nuclear, wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate.” g. Note 1 in Attachment 1 states: “The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.” If MOD-025-2 data required by Transmission Planners, why wouldn’t the data provided by Generator Owners per MOD-010 for Real and Reactive Power capability be the same data that is developed under MOD-025-1? The SAR for this project stated its purpose: “To ensure that generator models accurately reflect the generator’s capabilities and operating characteristics. |
| No |
| Footnote 4, not Footnote 5, addresses the question. Typo in Footnote 4: The word “on” should be deleted in this phrase in the last sentence: “...if the final model is not validated from on load date under...” |
| No |
| For ease of reference, we suggest that the three examples in the Background section of the Comment form be incorporated into Attachment 1 or as a separate attachment in the standard. |
| No |
| We agree with exempting base load units; however, the term “base load” or “base |

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| loaded" is not referenced in the standard. We could not find the exemption or a definition of "base load" in MOD-027-1. |
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| No |
| See comments to Question 2 above. |
| Yes |
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| We have these additional comments: a. Regarding Blackstart Resources, the revision to R4, Part 4.2.4 would only apply to Blackstart Resources that are "material to and designated as part of a Transmission Operator's restoration plan." The Glossary definition of Blackstart Resources already requires them to be part of a Transmission Operator's restoration plan, so that language is redundant and should be removed. Our concern is the requirement that Blackstart Resources also be "material to a Transmission Operator's restoration plan." Who would judge a Blackstart Resource's materiality? The standard leaves this issue open, which is unacceptable. We suggest that Part 4.2.4 be rewritten as follows: "Any generator, regardless of size, that is a Blackstart Resource. b. Typo: in R1, "In-service" (not a Glossary term) should be "in-service." |
| Group |
| Bonneville Power Administration |
| Chris Higgins |
| Transmission Reliability Program |
| Yes |
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| Yes |
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| Yes |
| BPA believes that the applicability from PRC-19-1, 4.1.2 "Transmission Owner that owns synchronous condenser(s)", should also be applied to the applicability of MOD-025-2 with respect to Transmission Owners. |
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| No |
| BPA believes that partial load rejection is not a suitable test for validating on-line governor response. Most turbine controls, including digital, analog, and mechanical, have different sets of settings for on-line and off-line, and often isolated operations. The settings are quite different, therefore, BPA believes using off-line settings for on-line studies is incorrect. Recording under-frequency events is the preferred approach for governor response validation. BPA recommends removing partial load rejection as an acceptable approach for governor response validation. |
| Yes |
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| No |
| BPA believes that the Generator Owner needs to provide evidence that a |

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| generating unit is operated as base loaded. It will be very useful to clarify the "base loaded" terminology as operating with control valves wide open or at the temperature limit, as "base loaded" is often used for different purposes in power plants. |
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| Yes |
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| Yes |
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| Individual |
| Keira Kazmerski |
| Xcel Energy |
| Yes |
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| Yes |
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| Yes |
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| Measure M1 says that the Generator Owner must provide evidence that it has supplied the Transmission Planner with temperature corrected values upon request. Making temperature corrections is not stated in the Requirements or the Attachments. In essence, this is creating an additional requirement within the Measure which is not permissible. If the Drafting Team adds a requirement to perform temperature correction, then Xcel Energy strongly recommends that a Technical Reference be added to provide guidance doing the corrections so there is consistency in how the various Generator Owners perform the calculations. |
| Yes |
| The footnote that should be referenced in the question is Footnote 4. Xcel agrees that the control mode differences when using a partial load rejection must be identified. |
| Yes |
| Xcel Energy believes Attachment 1 describes more than periodicity and suggests that the first column be titled "Verification Condition" and the second column be titled "Verification Timeline" since several lines are describing how much time following an event or condition is available to complete verification (not the periodicity of the verification). |
| Yes |
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| For combined cycle steam turbines that operate with turbine control valves wide open it appears that verification is not required based on line 10 of Attachment 1. Is this a correct interpretation, or would it still need to be verified if the combustion turbine(s) supplying energy to the HRSG(s) respond to a frequency disturbance and cause the steam turbine output to respond, albeit with a very long time delay? |
| Yes |
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| Yes |
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| Group |
| Imperial Irrigation District (IID) |
| Jesus Sammy Alcaraz |
| IID |
| Yes |
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| Not applicable to IID - abstained |
| Yes |
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| 2.3 and 2.4 need clarification whether the real and reactive tests are run separately or concurrently and if that is 1 hour each or 1 hour total. |
| Abstain. Not applicable to IID. |
| Abstain. Not applicable to IID. |
| Abstain. Not applicable to IID. |
| Abstain. Not applicable to IID. |
| Yes |
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| Yes |
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| The standard is still difficult to read and determine the applicability to the reliability to the BES. For example, it could not be determined in a first, second, or third reading (with team discussion) whether the standard is suggesting we change the maintenance or operations setting by the manufacturer's OEM. |
| Group |
| Santee Cooper |
| Terry L. Blackwell |
| South Carolina Public Service Authority |
| Yes |
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| No |
| Clarification should be made on applicability. Does this apply only to stand alone synchronous condensers, or are hydro units that can be used in condensing modes, |

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| also included. Also, we believe that the 20 MVA rating is too low for this standard. We would suggest that the same threshold as used in MOD 26 and 27 (100 MVA) be used. If necessary, the regions can set more restrictive thresholds. |
| Yes |
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| • Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that's not included in R1, Attachment 1 or Attachment 2. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. • Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. • Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which laid out a process where an engineering review and operating data should be performed 1st and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the regions planning and generator operators. This approach should be adopted as an additional method to verification. • Attachment 1, Periodicity for conducting a new verification: 2) We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. • The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. • Attachment 2, Summary of Verification – What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. • Applicability Section – change "bulk power system" to "BES". • Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or "sister" units should be allowed. • Testing a unit to the limits of its' protective function (such as overvoltage) creates the possibility for an unplanned unit trip, particularly problematic on nuclear units. |
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| Individual |
| David Youngblood |
| Luminant Power |
| Yes |
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| Yes |
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| Yes |
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| Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour. 2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions: 2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. 2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section 3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2). On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope. Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the simplified one-line diagram ..." Generator Owners can fill in the appropriate quantities at locations A-F. As an |

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| example, on some units values would be input for A, B, and F and NA entered for C, D, and E. For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard. |
| Yes |
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| Yes |
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| No |
| Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and specifically include the exemption that excludes units that are base loaded in the standard. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3). |
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| Yes |
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| No |
| Luminant disagrees with the need to illustrate coordination of the phase distance relay with AVR controls. The sample R-X diagram does not indicate how the relay is coordinated with field forcing capability. Since this function is covered in the generator loadability standard currently under development, Luminant recommends that this function be removed from the R-X diagram. |
| Luminant recommends in Requirement R1 that the coordination with Protection System be modified to reference the "applicable Protection System devices as referenced in Section G". As written, Protection System is all inclusive and would require verification of settings beyond the scope of this standard. |
| Individual |
| Joe Petaski |
| Manitoba Hydro |
| Yes |
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| Yes |
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| Yes |
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| Manitoba Hydro is voting negative for the following reasons: (1) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. (2) - Transformer Tap Settings - Under "Summary of Verification", transformer tap settings should be replaced by transformer voltage |

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| ratio as tap settings on their own do not provide sufficient information. (3) - Effective Date 5.3 - 5.3 is too specific and should not be a separate sub-section in the Effective Date section. 5.3 should be removed and replaced with a general note explaining how verification percentages should be calculated for wind farms. Suggested wording - "Note - With respect to wind farm sites, the level of completion of verification shall be calculated on the basis of the number of sites, rather than the number of turbines at each site." (4) - Temperature Range - Manitoba Hydro suggests that the GO should be required to provide a unit's performance in a reasonable temperature range as specified by the Transmission Planner. (5) - Consistency in reference to capability curve - a unit's capability curve is referred to as a D-curve, D-Curve, thermal capability curve, Thermal Capability Curve, and MVAR capability curve in the standard. References to the curve should be consistent. We suggest the curve be referred to as 'Generator Capability Curve'. (6) - Notes 2 and 3 - Notes 2 and 3 should be removed from the standard as they do not seem to be required for compliance purposes and their inclusion creates a lack of clarity. (7) - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to all standards in this project. |
| Yes |
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| No |
| See comment (3) provided in Question 8. |
| No |
| See comment (2) in Question 8. |
| Manitoba Hydro is voting negative for the following reasons: (1) - Verification of identical units - The standard should address the verification of identical sister units. There is no reason to test two identical units. (2) - 'Base Loaded' - The drafting team should clarify what is meant by 'base loaded'. Manitoba Hydro believes that it is important to verify base loaded units. (3) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. |
| Yes |
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| Yes |
| Manitoba Hydro suggests that example curves be provided for variable generation plants. |
| Manitoba Hydro is voting negative for the following reason: (1) - Implementation |

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| time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. |
| Individual |
| Jack Stamper |
| Public Utility District No. 1 of Clark County |
| Yes |
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| Yes |
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| Yes |
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| MOD-025 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60% and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-025. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard. |
| No |
| My Utility's only generator is a combustion turbine with a steam turbine and generator all attached to one shaft. Any load rejection event decreases the life of the components and should be avoided unless absolutely necessary. While partial load rejection testing may not significantly impact other forms of generation (i.e. hydro) the GVSDT needs to exercise caution in using simulated load rejection as a means of testing generator response. |
| Yes |
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| Yes |
| I agree with the concept but have been unable to find where in the proposed standard such an exemption is described. My Utility has one generator that is always operated as a baseloaded unit. |
| MOD-027 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 25%, 50%, and 75% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-027. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard. |
| Yes |
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| Yes |

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| PRC-019 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60%, and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with PRC-019. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard. |
| Individual |
| Mauricio Guardado |
| Los Angeles Department of Water and Power |
| Yes |
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| Yes |
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| Yes |
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| Under MOD-025 Attachment 1, “Periodicity for conducting a new verification”, Item 2, LADWP believes that the term “operation data” needs to be further clarified. Please provide the methodology and list of data types that qualify as meeting the requirement for verification using historical operational data. |
| Yes |
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| No |
| The criteria “Consideration for Early Compliance” seems to parallel the language for the draft of MOD-026-1 which deleted the redundant statement of, “The Generator Owner has an existing verified model that is compliant with the requirements of this standards.” It is understood that the applicable entity is compliant if it meets this criteria. |
| Yes |
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| Provide examples for methodology and data meeting the requirement for verification using historical operational data in accordance MOD-027-1 Requirement R2; 2.1.1 for frequency excursion from a system disturbance. In regards to: 4. “Applicability” 4.2.2 Generating units connected to the Western Interconnection with the following characteristics: • Individual generating unit greater than 75 MVA This criteria seems to conflict with the Applicability requirement of MOD-025-2; 4.2.1, Individual generating unit greater than 20 MVA. Why are the generating unit MVA criteria different across the MOD Standards? |
| Yes |
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| Yes |
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| In regards to PRC-019-1, Attachment 1- Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency, since different entities might have different standards in their Generator Protection System Standards for their generating units, it is not clear if they need to superimpose only some specific protection curves or if they are going to be expected to provide the curves for all the equipment protection wired into their generator protection systems. Additionally, some protection equipment from different OEM's has time-dependent characteristics such as OELs. Since the reactive capability curve represents steady-state limits, representing OEL characteristics on the RCC is not completely straightforward. When providing examples, have you consider the economic impact on implementing those examples? |
| Group |
| Dominion- NERC Compliance Policy |
| Mike Garton |
| Dominion |
| Yes |
| Dominion agrees with splitting Requirement R1; but notes that Requirement R2 should be changed from "Real Power Capability" to "Reactive Power Capability." Additionally, Requirement R3 should be changed from "Real Power Capability" to "Reactive Power Capability." |
| Yes |
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| Yes |
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| Dominion points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2. Additionally, on Attachment 1 at 2.2, "Applicable Facilities" should be changed to "applicable Facilities" to be consistent with usage elsewhere in the standard. * VSL's for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33. * VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from "more than 12 calendar months but less than or equal to 13 calendar months" to "greater than 15 calendar months." * Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word "reactive" be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." * Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. * Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient |

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| conditions, if applicable, at the end of the verification period that the Generator Owner requires..." |
| No |
| Footnotes should not contain requirements. If necessary, then they should be moved into the requirements section (i.e. Footnote 4). Against giving the option of purposefully causing system disturbance (i.e. load rejection). It is unclear how this would benefit the reliability of the BES compared to the two other data collection methods available. |
| Yes |
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| Yes |
| Dominion agrees that base loaded units should be exempted; however, that exemption is not clearly articulated in the standard. Dominion recommends that a base load exemption statement be added to the “Applicability” section of the standard. |
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| Yes |
| Dominion agrees, but points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2. |
| No |
| Section G provides additional clarity. However, the Purpose, R1.1 and Section G do no fully align. It should be made clear that all generator protection system devices aren’t applicable. |
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| Individual |
| Dale Fredrickson |
| Wisconsin Electric Power Company |
| Yes |
| Requirements R1.2 and R2.2 have data submittal dates for Real and Reactive Power verification values. The required timeframe of “90 calendar days” needs to be clarified when using historical operating data. For example, if a date of 180 days ago is selected for the verification, how can the data be required within 90 calendar days? The due date for a verification using historical data does not seem very meaningful. |
| Yes |
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| Yes |
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| a. In Requirement R2.1, the capability is to be verified at the “normal expected maximum Real Power” value. Since the verification cannot always be done in ideal conditions, there needs to be more flexibility in acceptable MW values to account for non-ideal conditions, such as wet coal, for example. A value of “greater than 90 |

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| percent of normal expected maximum Real Power" is recommended instead of "normal expected maximum Real Power". b. Also in Requirement R2.1, the requirement for wind turbines is to have 90 percent of the turbines on-line for the verification. We support having a requirement of 50 percent of rated maximum Real Power, as specified in the ReliabilityFirst regional standard, MOD-025-RFC-01. Using a more attainable requirement for wind turbines will also eliminate the need for re-testing. The standard should have more flexibility for intermittent resources like wind. c. In Requirement R2.2, the capability is to be verified at the "minimum Real Power output". It may be difficult to operate the unit in a reliable and stable manner exactly at the "minimum" MW value. We suggest allowing more flexibility when verifying at the minimum Real Power value. We propose to allow a range from the minimum Real Power value to the minimum value increased by 10 percent of the rated maximum Real Power. For example, if the maximum Real Power of a generator is 200 MW and the minimum Real Power is 50 MW, the verification for Reactive Power at minimum Real Power could be done anywhere between 50 MW and 70 MW Real Power. This or some other means of providing greater flexibility at the lower end would especially be needed for coal units. d. In Measure M1, there is a reference to providing values corrected for ambient conditions, if requested. There is no mention of this in the Requirements section. This wording should be deleted, or else any such requirement should be specifically included in the Requirements section. e. In Attachment 1, 3.1, the values of Real and Reactive Power are to be recorded "at the end of the verification period." It is suggested that the average (mean) values of these quantities over the verification period should be recorded, rather than simply the last value. f. In Attachment 2, there is a requirement to provide net values at the high-voltage side of the GSU (Point F). This requirement should be deleted. The values for Gross, Auxiliary, and calculated low-side net are sufficient to document the verification. In addition, the required metering at this location may not be available. We have conducted field verifications for five years now, and the low-side values for MW and MVAR have been quite adequate. |
| No |
| There is not nearly enough confidence that governor testing on a unit connected to the system is safe or desirable, whether it is partial load testing or a change in the speed governor reference. Footnote 4 seems to make the value of any online testing very questionable. NERC should work with turbine-generator and controls suppliers (OEM's) to validate the concept of online testing of governor controls. The use of recorded data during frequency excursions also requires more information on what would constitute adequate data. In summary, more work on such a requirement for online testing is needed, as well as collaboration with equipment suppliers. |
| No |
| When it takes five pages to describe the periodicity requirements, the standard is overly complicated. |
| No |
| We agree with the concept of an exemption for units that are running most of the time. It is not at all clear where this exemption exists in the standard. Does this |

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| mean that a "base-load unit" never requires a model verification? If not, it is unclear what purpose this exemption serves. |
| a. In Section 3 "Purpose", reference is made to Bulk Electric System (BES) reliability. Then, in Section 4.2, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. b. In Section 4.2 Applicability, Footnote 2, the reference to startup or standby units should have further detail since these terms are not defined by NERC, or simply remove this footnote. c. In Requirement R1, instead of the Transmission Planner (TP) providing "instructions" on how the Generator Owner (GO) can obtain necessary models and associated information, the standard should require the TP to simply "provide" the model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. In addition, the TP should provide the OEM model data sheets or other data supporting the current in-use models in the dynamics database. d. In R2.1.1, the GO is required to provide documentation comparing the turbine/governor model response to the recorded response for a frequency excursion while online, or a change in reference while online, or a partial load rejection test. Since the GO usually does not have the capability to run such dynamic studies, it is not clear how will it obtain the "model response" for comparing to the recorded response. When there is more collaboration between NERC, Generator Owners and OEM's on the methods for online governor verification (see Question 5 response above), only then should there be any requirement that the GO "provide the recorded response for a frequency excursion". As presently written, R2.1.1. can only be required of the TP. Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the data required in R2.1.1. This standard is too far ahead of the existing capabilities for verifying these controls. More work is needed, and it is strongly suggested to bring OEM's into the process to enable the development of a useful standard. e. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the business need to develop these equivalent models like the TP does for system modeling. This requirement would demand resources in return for no increase in reliability. The requirement should allow the GO the ability to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate model. f. It is not clear how this standard relates to variable resources such as wind farm. It is suggested that these generating sources should be specifically |

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| excluded from the Applicability. |
| No |
| The Applicability section in 4.2 refers to generators being connected to the “bulk power system”, or BPS. The reference should be to the Bulk Electric System (BES), which is defined by NERC. The BPS is not a defined term in the NERC Glossary, and using this term is extremely confusing and possibly misleading. The GVSDT’s use of the term BPS, here and in several other standards, opens the door for applying NERC standards to generating units which are connected to the system at voltages below 100 kv. The applicability should solely be to generating units of the MVA size required for registration and connected to the BES at 100 kv or higher, and to those generators which are blackstart resources. |
| Yes |
| It is not clear how the field current limiters or trip settings are plotted on the P-Q diagram, since these parameters are dc field amps. |
| a. In Requirement R1.1.1 , the requirement to verify that Protection System devices are set to “operate before conditions cause damage to equipment” is not attainable and should be revised or eliminated. The best possible settings cannot guarantee that equipment will not be damaged. The best that can be expected is for protection settings to decrease the risk of damage, or to limit the extent of damage if it occurs. b. In Requirement R1.1.2, the requirement to make sure that the limiters and protection settings are applied to in-service equipment is not necessary, and should be removed. It can be expected that professionals in the electric power industry are aware of the need to verify that the settings on in-service equipment are proper. Though errors may occur, this is an obvious aspect of good utility practice and responsible care of assets. Therefore, there is no need for a regulatory requirement. In fact no regulation is able to totally prevent human error. Measure M1 also requires a similar change in this regard. c. In Section F Associated Documents, better references would be the following IEEE Power System Relaying Committee documents: 1. “IEEE C37.102-2006 IEEE Guide for AC Generator Protection”, and 2. “Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee. |
| Individual |
| Anthony Jablonski |
| ReliabilityFirst |
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| ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring generator verification of both Real and Reactive Power on a continent-wide level. This standard will also remove the Regional “fill in the blank” obligation to have Regional generator verification requirements. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this |

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| standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. b. ReliabilityFirst requests clarification on why the term “Bulk Power System” is used rather than “Bulk Electric System.” ReliabilityFirst interprets, that by using the term “Bulk Power System”, units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. 2. Measure M1 a. The term "if requested" needs to be removed from the fourth line of Measure M1. The condition of “when requested” is not listed in Requirement R1. 3. VSL Requirement R1 a. The VSLs under the first “OR” statement should reference Attachment 1. This same language should be included in the VSLs for Requirements R2 and R3 as well. Here is an example of a “lower” VSL: “The Generator Owner verified the Real Power capability, per Attachment 1, and submitted the data but was missing 1 to 33 percent of the data. b. The Moderate VSL under the first “OR” statement, should be changed to state “…missing 34 to 66 percent of the data.” As currently stated, missing 33% would fall under both the Lower and Moderate VSL category. |
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| ReliabilityFirst abstains and offers the following comments for consideration: 1. Facilities Section 4.2 a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. b. ReliabilityFirst requests clarification on why the term “Bulk Power System” is used rather than “Bulk Electric System.” ReliabilityFirst interprets, that by using the term “Bulk Power System”, units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. 2. Requirement R1 a. For the purposes of NERC standards, “bullets points” are to be considered “OR” statements. ReliabilityFirst believes all the “bullets points” in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) 3. Requirement R4 a. ReliabilityFirst seeks clarification on the rationale/justification for the 180 calendar day time period for the Generator Owner to provide revised model data to the Transmission Planner? ReliabilityFirst believes this data should be provided within 90 calendar days consistent with other requirements in the standard (which require 90 calendar day submittals). 4. Proposed new Requirement R6 a. ReliabilityFirst recommends the inclusion of a new Requirement R6 which would be a follow-up to Requirement R5. Requirement R5 requires the Transmission Planner to notify the Generator Owner if the model information is not useable (along with the technical description) but there is no corresponding requirement for the Generator Owner to make the model “useable” and submit it back to the Transmission Planner. ReliabilityFirst believes the feedback loop needs to be closed and a new Requirement R6 should be included. 5. VSLs – General format a. A number of VSLs use a parenthetical indicating the associated requirement number, some VSLs use the language “per R1”, and other VSLs do not indicate the requirement number at all. ReliabilityFirst suggest using one consistent style/format and apply to all VSLs. b. For consistency when referencing subparts, |

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| the VSLs should have the same nomenclature. For example, the VSL for R2 states "Requirement R2, Subparts 2.1.1, through 2.1.5." while the VSL for R5 states "Requirement R5, Parts 5.1 through 5.3." ReliabilityFirst suggest using the following format: "Requirement R1, Part 1.X". 6. VSL for Requirement R2 a. ReliabilityFirst recommends the language be consistent across all four sets of VSLs. For example the Lower VSL states "provided its verified model(s)" while the Severe VSL states "provided its verified turbine/governor and load control and active power/frequency control model(s)." ReliabilityFirst suggests using the language as stated in the Severe VSL for the other three VSLs. b. There is no reference in the VSLs associated with Requirement R2, Part 2.2. ReliabilityFirst recommends adding a set of VSLs to cover a possible non-compliance with Requirement R2, Part 2.2. |
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| ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. b. ReliabilityFirst requests clarification on why the term "Bulk Power System" is used rather than "Bulk Electric System." ReliabilityFirst interprets, that by using the term "Bulk Power System", units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES 2. Requirement R2 a. ReliabilityFirst recommends removing the following language from Requirement R2: "that are expected to affect this coordination." The term "expected" is ambiguous and is hard to measure. b. ReliabilityFirst recommends adding the phrase "with applicable Facilities" after the opening phase of, "Each Generator Owner and Transmission Owner." The addition of this language will be consistent with the language in Requirement R1. 3. Measure M1 a. The language in Measure M1 is set up more like a requirement /RSAW rather than a Measure. Measures should be set up to provide identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Furthermore, the Measure should not introduce new concepts or requirements. ReliabilityFirst recommends the following for consideration: "Each Generator Owner and Transmission Owner with applicable Facilities will have evidence that it coordinated the voltage regulating system with the applicable Facility capabilities and Protection System settings as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed." 4. Reference Section a. ReliabilityFirst recommends removing the "Examples of Coordination" from the standard since they are simply guidance (as stated in the note - This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions). Examples would be more appropriately housed within an associated whitepaper, FAQ, guidance document, etc. and should not be housed within a NERC Reliability Standard. 5. |

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| VSLs and associated Requirements a. When timeframes are referenced within the VSLs (and associated Requirements), ReliabilityFirst recommends strictly using a month format (e.g. 60 months) instead of a year/month format. This would be consistent with various other NERC Reliability Standards. |
| Individual |
| Kirit Shah |
| Ameren |
| Yes |
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| Yes |
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| Yes |
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| (1)R1 and R2 require verification of the Real and Reactive Power capability of Applicable Facilities using Attachment 1. Attachment 1 ONLY allows verification by: (a) staged verification, or (b) verification using operational data. We suggest that the GVSDT add an additional option allowing engineering analysis verification. (2) Replace the term "Bulk Power System" with "Bulk Electric System" in Applicability section, items 4.2.1, 4.2.2, and 4.2.3. The use of the term "bulk power system" throughout Section 4.2 Facilities should be replaced with the term "Bulk Electric System (BES)". The use of the term bulk power system, which is not defined in the NERC Glossary, is problematic in determining which generating units and plants must comply with this new Standard. (3)In Note 1 of Attachment 1 to the draft MOD-025-2 standard, it is recognized that, at a given time, one or more generating units under test may not be able to reach full reactive capability as expected based on a review of the unit(s) thermal capability curve due to prevailing transmission system conditions. It is further recognized that the verified reactive power values obtained via testing will likely not agree with the reactive capability as used in model data submitted in compliance with Reliability Standard MOD-010. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed. As presently written, MOD-025 Attachment 1 allows only staged testing of the generating units or use of operational data. (4)The Attachment 1, Note 1 refers to the following. (a) The verification values produced by compliance with this new Standard. (b) The manufacturer's D-curve values. (c) The Transmission Planner's database values. (d) The MOD-010 values. Such multiple set of values appear to be in conflict with the purpose of the standard which is, "…ensure accurate information on generator gross and net Real and Reactive Power capability…is available for planning models used to assess Bulk Electric System (BES) reliability"? In this regard we fail to see a need for verification as suggested in this standard. We request the GVSDT to clarify if our interpretation is incorrect. (5)The middle paragraph on page 1 of Attachment 1 requires that any generator that can be operated in both generation mode and synchronous condenser mode must be verified in EACH mode of operation – generation and synchronous |

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| condenser. We believe there should be exemptions for small hydro units which in frequently operate in the synchronous condenser mode. (6) Applicable size for the generating facilities in MOD-025-2, MOD-026-1, and MOD-027-1 should be consistent, which is a minimum size of 100 MVA. (7) Rather than a constant 5 year verification cycle, we suggest that the GVSDT consider a 10 year verification cycle with annual confirmation of the most recent verification. The first cycle could make use of the latest MOD-024-1 and MOD-025-1 values. (8) An option should be added for plants with more than one identical unit (sister units) allowing testing for one unit in place of all the identical units. Each cycle the GO should test a different sister unit until all have been tested. (9) Likewise, if MOD-010 data is still required, its requirements should be incorporated into this Standard in the next draft. (10) In the Implementation Plan, with the effective date of this standard, the previous version of related standards should be retired such as MOD-010. (11)Violation Severity Levels - R1 Moderate should be 34 to 66 percent. (12)In the R1 Severe Violation Severity Level, the last paragraph has same time frame shown as the R1 Lower VSL (more than 12 calendar months but less than or equal to 13 calendar months). (13)Violation Severity Levels - R2 Severe last paragraph has same time frame as R2 Lower – similar situation to comment above. (14)Violation Severity Levels - R3 Severe last paragraph has same time frame as R3 Lower – similar situation to comment above. |
| No |
| We agree with the inclusion of an additional option, but find this footnote to be a concern. The footnote is too vague and provides no guidance on an appropriate model, the acceptable quantitative differences or any way for a GO to benchmark the adequacy of its verification. |
| No |
| (1)We believe that any testing or verification required by MOD-012, MOD-013, MOD-026 and MOD-027 should have the same periodicity so that all required tasks can be performed in parallel. Note that earlier we have suggested a 10 year cycle. (2)We believe Attachment 1, row 4 is intended to allow “sister unit” testing so plants with multiple identical units are not required to verify each identical unit during each verification cycle. If this is the case, please clarify this option more clearly in the Attachment or the Standard. |
| No |
| We are in agreement with the exemption in the statement, but unclear where it is provided in either the Requirements or Attachment 1. Please clarify how this option is allowed. |
| (1) Footnote 4: “...validated from on load data...” For clarification, please consider that this be changed to read “...validated from on-line unit data...”. (2) Regarding the title of Attachment 1 “Turbine/Governor and Load Control and Active Power/Frequency Control Model Periodicity” – should the ‘and’ before ‘Active Power/Frequency Control’ be changed to an ‘or’ to be consistent with the title of the draft Standard? Similarly, the phrase “turbine/governor and load control and active power/frequency control” appears in several places in the VSL table. Should the ‘and’ before ‘active power/frequency control” be changed to ‘or’ in these instances for consistency? (3) Violation Severity Levels - R5 Moderate: There is |

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| conflict here because failure to respond within 150 days automatically puts one in the High category. (4) There is a concern that different effective dates between the MOD-26 and MOD-27 standards will be burdensome for the Transmission Planner to track and analyze model updates. The Transmission Planner would prefer to receive the exciter and governor models updates for a specific unit at the same time. (5) Replace "Bulk Power System" with "Bulk Electric System" In the Applicability section, items 4.2.1, 4.2.2, and 4.2.3. (6) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website. (7) R2 and R2.1 require each GO to provide for each generator a "...verified turbine/governor and load control...model..." The GVSDT should provide guidance on how to quantitatively determine when a model is verified for each unit. |
| Yes |
| The VRF and VSL need to be modified to put the significance to BES reliability in proper perspective; refer to our comments in response to question 11. |
| Yes |
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| Please clarify that R2 applies to Generating / synch condenser coordination as stated in A.3 in order to avoid confusion with the GO-TO Protection System coordination being addressed under Project 2007-06 and its proposed PRC-027-1. (2) We believe that R2 is confusing as written. Please restate with subparts to clarify. Insert 'latter of' before 'identification or implementation' to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. For a given generator several changes may be identified at different times and then implemented during a common major overhaul or maintenance outage. A ten year periodic coordination review is sufficient if no other change has triggered a review; redoing a study more often than needed distracts valuable resources for other activities more important to BES reliability. We propose: (R2) Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1: (2.1) At least once every ten years; or (2.2) Within 90 calendar days following the latter of identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following ... (3) From our perspective High VRF is not justified. We suggest changing to Medium risk which in our opinion is a stretch for the following reasons. (3.1) PRC019 capability, limiters, and protection apply to a specific Element, one generator at a time, and if are not coordinated that single generator may be removed from service or may be damaged. But the loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures. If the generator trips because of loss of field, BES voltage state will actually improve. Furthermore, many generators have very few operating hours per year and pose little risk to the BES. High Risk requirement is not met. (3.2) PRC019 is not comparable to either PRC012 or PRC023. (3.2.1) Loss of a single generator differs from SPS in PRC-012 which trips more than one Element. (3.2.2) The vast majority of the generators under PRC019 have much less capability than the Elements under PRC-023 which are either >200kV or critical BES lines and transformers in PRC-023 which are major Elements. FERC Guideline 3 is not met. (3.3) In an emergency condition, lack of intended coordination could affect the electrical state if many generators |

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| tripped. This supports Medium not High for FERC Guideline 4. (4) VSL is misaligned with respect to this standard Facilities and Implementation. (4.1) Please add a % of Facilities threshold in R1 to better match the risk to BES reliability. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. (4.1.1) For R1, we suggest thresholds of 5% of the entities Facilities for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe VSL. (4.2) For R2, please replace the time-based (days late) with % of MWh (or MVar-hours for synchronous condensers) during the period of violation to more properly account for aggregate impact. For example, (4.2.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.' (4.2.2) Moderate VSL becomes '…more than 5% and less than 10%' (4.2.3) High VSL becomes '…more than 10% and less than 15%' (4.2.4) Severe VSL becomes '… more than 15%' (5) VRF and VSL need to be applied commensurate with BES reliability risk. (5.1) We believe that in this standard, VRF High and VSL Severe is not justified as drafted, and likely to lead to the unintended consequence of disabling limiters and protection to avoid compliance burden. (5.1.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.' (5.1.2) Moderate VSL becomes '…more than 5% and less than 10%' (5.1.3) High VSL becomes '…more than 10% and less than 15%' (5.1.4) Severe VSL becomes '… more than 15%' (6) Violation Severity Level R2: The increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Also in R2 you need a space between "5years". (7) There is no mention of working with the Transmission Planner anywhere in the standard. The TP will be the entity that determines the Steady State Stability Limit. (8) Please replace "Bulk Power System" with "Bulk Electric System" in numerous places. (9) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website.. |
| Individual |
| Kathleen Goodman |
| ISO New England Inc. |
| No |
| Attachment 1 does not require a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% for up to 12 months. This is too long a period for a generator to be providing less than expected power output. |
| Yes |
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| No |
| We feel that the Reliability Coordinator is the appropriate entity to receive this data. In our area a number of entities are registered as Transmission Planners, to avoid confusion this data should be submitted to a single entity who will then |

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| distribute the data. |
| This testing will be difficult to stage due to the four point reactive power testing. The power system will have to be reconfigured in many cases to allow for the changes in generator reactive output For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are “on-line”. For reactive testing, would this be better stated as 90% of the plant’s capability available, considering some wind turbines maybe be able to produce/absorb reactive power with no real power production, or does on-line just imply that the turbine breaker is closed and no requirement for real power production? In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power connected at the high-side of the generator step-up transformer (point D) and Aux or Station Service Real Power connected at other points of interconnection (point E) with no discussion? Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)? |
| Yes |
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| Yes |
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| No |
| Base loaded units could provide governor response for over-frequency events and should have verified models for this event. |
| We feel that some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical. |
| Yes |
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| Yes |
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| Individual |
| Mark B Thompson |
| Alberta Electric System Operator |
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| 1. In section 4.2, the AESO considers the existing applicability for reactive power verification to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a |

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| change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect, or some qualifying language needs to be added. |
| No |
| The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units. |
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| 1. In section 4.2.2, the AESO considers the existing applicability for model validation to be more appropriate: • Connected to a transmission grid at 60 kV or higher voltage; and • single unit capacity of 10 MVA and larger; or • facilities with aggregate capacity of 20 MVA and larger. 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. 3. Requirement R4, as written it appears owners of generating units that plan to change out the governor are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change. |
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| Individual |
| Darryl Curtis |
| Oncor Electric Delivery Company |
| Yes |
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| Yes |
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| No |
| In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities. |
| No |
| Yes |
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| Yes |
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| Yes |

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| No |
| Yes |
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| Yes |
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| No |
| Individual |
| Cristina Papuc |
| TransAlta Centralia Generation LLC |
| No |
| Do not agree to Attachment 1 item 2.2 and 2.3. Refer comments below: 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Typically, the maximum overexcited and under-excited reactive capability is tested at the Rated or full Real Power output of generator, not at the minimum Real Power output of generator. 2.3. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour. Please verify the reason for a minimum of one continuous hour. |
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| No |
| In some cases, the data at the interconnection point (such as the high side of generator step-up transformer) may not come directly from GO as the measuring instrumentation may not be owned by the GO |
| The Transmission Operator (System Operator) should be included as an applicable functional entity since the Reactive Power verification test will to be coordinated by Transmission Operator (System Operator). There should be a requirement assigned to TOP for such coordination. |
| Yes |
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| Yes |
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| Yes |
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| Yes |
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| Yes |
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| R2. Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or |

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| within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, Please verify the reason for “at least once every five years”. If the existing practice (such as 5 years testing in the WECC region) shows that for those generators without changing any associated equipment the models do not change more than 5 years, it is recommended the duration be longer than 5 years. |
| Group |
| Tacoma Power |
| Chang Choi |
| Tacoma Power |
| Yes |
| None |
| Yes |
| None |
| Yes |
| None |
| None |
| Yes |
| The question above should have referenced footnote 4. |
| No |
| Attachment 1, especially the column titled “Verification Periodicity” is difficult to interpret. For example, for the “Event Triggering Verification” row titled “Initial verification for a new applicable unit…” the periodicity is stated as “Record unit Real Power response to first frequency excursion…. OR record unit Real Power response for….reference change….no more than 365 calendar days from the commissioning date”. This language implies that there is no stated periodicity applied if the generator owner elects the frequency excursion event option. Rather the generator owner must interpret that such an event has occurred, even if it happens 15 years later, and then has 365 calendar days to verify the model. The periodicity as applied to existing fleet and new/changed fleet should be made easier to interpret. |
| No |
| A text search of all three standards did not return the term “base loaded”. Tacoma is not aware of an industry standard definition for the term “base loaded”. If a unit is typically left at static output to meet base system load requirements it may likely still have droop as part of its governing system. As such, it would still be expected to respond to system frequency excursions. |
| Requirement R2.1.5. It may be difficult to model the characteristics of outer loop controls (such as operator set point controls and load control) within the typical industry-standard modeling software parameters. |
| Yes |
| None |
| Yes |
| None |

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| What if, during the Implementation Plan, it is discovered that coordination does not exist, but the situation is resolved before the effective dates contained in the Implementation Plan? Would this constitute a violation of PRC-019-1? The Implementation Plan uses the phrase “…shall have verified…” R1.1.1 would require that “…the Protection System is set to operate before conditions cause damage to equipment…” Yet, the NOTE under Section G (Reference) states that “this standard does not require the installation or activation of any of the above limiter or protection functions.” The latter statement could be construed (in the extreme case) to permit little or no protection functions, but this would appear to violate R1.1.1. Clarification is requested, as these two portions of the standard appear to conflict. Under R2, is the 5-year interval (a) 5 calendar years or (b) closer to 1825 calendar days? R2 requires that entities “…verify the existence of the coordination identified in Requirement R1…within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following…” Protection System component changes is listed. If a component is replaced in-kind, is it actually required to verify the existence of the coordination identified in both Requirement R1.1.1 and R1.1.2, or just R1.1.2? Or, would this change be N/A to PRC-019-1 because it is not “…expected to affect this coordination…”? Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity. |
| Individual |
| Dennis Sismaet |
| Seattle City Light |
| No |
| Attachment 1 “Periodicity for conducting a new verification:” Frequency of tests should correlate better with MOD-026 and MOD-027, which is once every 10 years. |
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| Yes |
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| Attachment 1 “Verification specifications for applicable Facilities:” section 2.3: It will be difficult to test at maximum power for one continuous hour at some plants due to operating restrictions regarding water flow or other factors. |
| No |
| It appears but is unclear if a partial load rejection test is acceptable. The unit on-line test is difficult to capture without functioning Digital Fault Recorders, which are not available at all plants. Seattle City Light requires a clarification in the text if on-line testing required or is a partial load rejection test allowed. |
| No |

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| Once every ten years seems reasonable with load rejection testing, but it is unclear if frequency excursion modeling is required during operation. |
| Yes |
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| On-line monitoring is required to meet this draft Standard but is not yet available at all many generating plants. For the monitoring proposed, it will requires very high resolution Digital Fault Recorders that currently are not available nor required (side note: as of right now in WECC existing generating plants below 1500 MW are not required to have DFRs, and many or most do not). The cost vs. benefit of such a demand should be reviewed and clarified. |
| Yes |
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| Yes |
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| New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary. |
| Individual |
| Russell A. Noble |
| Cowlitz County PUD |
| Yes |
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| Yes |
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| Yes |
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| Cowlitz understands the SDT must comply with FERC directive in Paragraph 1321. However, Cowlitz disagrees that requiring verification every five years will not be too burdensome to the GO. Cowlitz is not confident that verification will be possible with operational data, and will be forced to verify via staged verification for at least two of the test points. We suggest that staged verification for four test points be required every 10 years with operational verification within 10% of at least one test point from the last staged verification being made no greater than 5 years after the staged verification. Should all four staged test points be confirmed via operational verification within 5 years of the last staged verification, then staged verification will reset to 10 years. If operational verification can’t be provided within 5 years of the last staged verification, then one point must be verified via staged verification 5 years after the last full staged verification (all 4 points). Cowlitz also disagrees with the generation applicability set at 20 MVA. This is arbitrary; FERC made no |

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| mandate in this regard and in fact shared a “concern with several commenters that such a requirement for all [Registered] generators may not be necessary.” Cowlitz respectfully points out that it appears the SDT made no effort at all to determine true Reliability impact. Drafting Reliability requirements with no Reliability return must be avoided. SDT statements that simply state “the effort is not considered to be costly or burdensome” is not acceptable as it only offers an opinion without substantiating evidence. |
| Cowlitz respectfully asks that the Standard number be referenced in multiple standard comment forms. Did you mean footnote 4? As a small GO, Cowlitz would have to hire a consultant to comment on this question, and therefore must defer to larger GO’s who have the appropriate subject matter experts available. |
| Cowlitz could not find the guidance. |
| Cowlitz could not find any mention of “base loaded unit” in MOD-027-1. |
| In the applicability section 4.2.2, second bullet states “comprised consisting.” Cowlitz suggests deleting one of these words. Cowlitz also struggles with why the generation applicability is set at 75 MVA for the Western Interconnection. Is the SDT trying to encompass 80% of all Registered generation? Cowlitz abstains as it appears this standard may require information that may not be possible to obtain, but can’t offer technical basis at this time and will defer to commenters better equipped to answer. |
| No |
| Cowlitz believes 20MVA is meant to catch users who may adversely affect the BES, such as via a faulty BES Protection System a small generator may own. The registry criteria should not endeavor to identify generation that is necessary for the support of the BES. Cowlitz feels this standard applicability conflicts with Phase 2 of Project 2010-17, Definition of Bulk Electric System. This standard should only apply to BES generation which currently is poorly defined. If this standard is needed urgently to cover a Reliability gap, Cowlitz would suggest an arbitrary 200 MVA applicability be established and a phase 2 SAR be established to adjust the standard to apply to BES generation after completion of Project 2010-17. Cowlitz commends and thanks the SDT in addressing this question. |
| Yes |
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| Group |
| Southern Company |
| Antonio Grayson |
| Operations Compliance |
| Yes |
| a) The method of reactive power capability determination described in "Note 2" of Attachment 1 should be included as an allowable third (3rd) method of reactive power capability verification. (as an alternative to using operational data or staged testing) b) Any verification specifications listed on Attachment 1 that merely repeat the line items of data requirments shown on Attachment 2 should be eliminated - they are not necessary in both locations. |

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| No |
| a) The applicability threshold is too small. Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to individual unit size of 100 MVA for the Eastern Interconnection. b) We feel that machines able to run either as a synchronous condenser as well as a synchronous generator need only be validated in generator mode. It is unclear if the requirement for synchronous condensers is for machines with a single mode of operation. c) The individual unit size criteron value should equal the gross aggregate plant/ Facility threshold value. |
| Yes |
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| 1) Applicability, Section 4: Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to focus on standard requirements that have significant impacts on system reliability, and including smaller units (without demonstrating their criticality to the system) seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where relability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. 2) Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 3) Attachment 1, Verification specifications for applicable Facilities, Item 2: Delete the requirements for mandatory “staged testing”. Allow staged testing as an alternative. There is no industry consensus that staged testing is superior or achieves better reliability results for modeling purposes than the use of operational data coupled with a proper engineering study. A staged test performed every 5 years in our experience is not a substitute for proper planning, proper implementation of limiter and protection settings, equipment monitoring, unit data trending, and operational awareness and identification of plant equipment problems that could impact the MW or MVAR capabilities of a unit. Staged testing alone typically does not prove a unit’s reactive capability, because the unit’s true reactive limit cannot be reached due to transmission voltage and reliability constraints during the test period. We believe staged testing alone cannot accomplish the reliability purpose of this standard. While staged testing can identify problems such as incorrect AVR limiter/protection settings or non-optimum transformer tap settings, these problems can be identified and corrected without staged on-line testing. 4) Attachment 1, Verification specifications for applicable Facilities, Item 3.4: This increases the complexity and reporting requirements for compliance. In practice, we believe the margins of error in transmission models do not require this level of detail and accuracy for periodic verification of unit MW capability. For the purposes |

of this standard, we believe recording of the MW for typical normal summer or winter conditions is sufficient. If a unit's MW capability is in question, TOP-002-2b R13 already has provisions for performing a more detailed verification, including ambient and water temperature conditions, at the request of the BA or TOP. 5) Attachment 1, Verification specifications for applicable Facilities, Note 1: Revise the last sentence to state, “The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit’s reactive capability for extreme system conditions. See Note 2.” 6) Please add page numbers to every page of the standard. 7) Attachment 2, Summary of Verification – What is the purpose for the fifth bullet? MVARs are a function of both the generator voltage and the system voltage. Thus, how to adjust the recorded Mvar values to rated generator voltage is not clear, is subject to dispute, and implies that engineering analysis is required to determine this result. 8) Attachment 2 Remarks – It is unlikely that the generator capability curve will be reached either during a lagging VAR test or during collection of operational data when a GSU tap has been set to support the normal system voltage ranges. The generator should be able to support the normal system voltage range without producing a large amount of Vars or amps so the Vars (or thermal capabilities) are held in reserve for extreme low voltage conditions. The transmission bus voltage will likely be the limiting factor during testing and normal operation. It is unlikely that capability curve limit will be reached during either a leading VAR test or during collection of operating data. The limiting factor again is likely to be the transmission bus voltage. Likely unit operational limits which will prevent demonstration of the full range of the generator capability curve include the minimum excitation limit, the generator minimum voltage limit, or the station service minimum voltage limit. We recommend the Remarks statement be replaced with a list of possible limiting factors with checkboxes. If the transmission system voltage or a plant voltage limit is the limiting factor, the results of the test are inconclusive without performance of a supplemental engineering study. 9) The responsibility for requiring and coordinating any staged testing for the purposes of model validation already resides with the owners of the transmission models (i.e., the PC, TP, TOP and/or RC), not the GO or GOP. See TOP-002-2b R13. The TOP should initiate the request for the test and work with the GO/GOP to schedule the testing at a time when system conditions are optimal for testing that specific unit. The GO/GOP should only be responsible for supporting the TOP/RC during test scheduling, conducting the test, recording the necessary plant data, and reporting the test data and results, including any plant limitations encountered during the test. The GO/GOP can also perform any technical reviews and/or additional engineering analysis necessary to determine or confirm the expected MVAR limits to be used in the transmission models. This approach will better serve the reliability purpose of the standard. 10) Measure M1 doesn't match R1, or Attachment 1 or 2 regarding the submission of ambient condition correction information. (appears in M1, but not in the others) 11) An entity should be able to receive credit for real & reactive capability verification that has been done in the past 5-6 years which resulted from following existing regional requirements 12) For cases where operational data is used for verification, submittal of the results within 90 days of the date the data is recorded is inappropriate. Use of operational data involves the review and

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| evaluation of unit data trends over an entire season as a minimum. Two seasons are optimum based on our experience. R1.2 and R2.2 should be revised to state, “within 90 calendar days of completion of the verification.” |
| Yes |
| The footnote number in the clean version is Footnote 4. The footnote reflects our concerns about the validity of data taken from partial load rejection testing when compared to the unit response during normal operating load levels. |
| No |
| a) R2 references Attachment 1 for periodicity, yet also includes a "365 day" statement. Please rely on Attachment 1 for the periodicity information and remove the parenthetical element from R2. b) On first glance, it is not clear that pages 14-18 all comprise Attachment 1 - please label each table. c) Please number the rows of the table so that they can be easily referred to. d) The GO is not aware of system frequency excursion events at each of their facilities to see if a Criteria 1 has occurred. e) should row 1 of the table on p 15 include "existing applicable unit"? h) Row 2 should be labeled "Recurring verifications" as "for an existing applicable unit" is superflous to subsequent. i) What is the time frame for the Criterion 1 frequency deviation? j) Row 4 of the table describes what is commonly termed "sister" units - the limitation to allow sisterhood for only those units at the same physical location should be relaxed to include all identical units for the same GO/GOP either within a Balancing Area, or alternatively, within the area of responsibility for a Reliability Coordinator. The GO should be allowed to take credit for units located within the same Balancing Area (or alternatively the Reliability Coordinator area of responsibility) if he can show that the physical location is not a factor in the comparison. k) It is not possible to comply with the R2 25/50/75/100% in 3/5/7/9 year implementation plan and fulfill the trigger verification of Row 5 of Attachment 1 table. |
| Yes |
| We agree that base load units should not be required to respond to demonstrate they will respond for underfrequency events and this should be reflected the transmission models. |
| Yes. 1) Applicability 4.2.1, 4.2.2, and 4.2.3 use the term “bulk power system" and should be “Bulk Electric System (BES)”. We believe the >100kV criteria language should be retained. We believe the exemption for units that, by design, do not respond to frequency should be clearly stated in the Applicability section. 2) It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. We believe this to be true even when it is part of a plant or Facility with an aggregate gross rating >100MVA. NERC is supposed to focus on creating standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. For plants and Facilities with an aggregate rating >100 MVA we recommend deletion of the two sub-bullets in 4.2.1, 4.2.2, and 4.2.3. In conjunction with this change, we recommend that R2, sub-part 2.2 be revised to state, “For plants or Facilities with gross aggregate rating greater than the specified thresholds in 4.2.1, 4.2.2, or 4.2.3, perform verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5. 3) The Eastern |

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| Interconnection frequency excursion criteria of greater than or equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don't provide data that is nearly as meaningful as excursions at 0.06 or 0.07." 4) Measure M2 uses the term applicable "Facilities" while R2 uses the term applicable "units". Either is acceptable to us, but the requirement and measure should use the same terminology. 5) The purpose statement is written in a convoluted form - a more straightforward presentation could be: "To verify the models used in dynamic simulations accurately represent the generating unit real power response to system frequency variations". 6) In Requirement R3, the paragraph above the three bullets would be more appropriate if moved below the three bullets. 7) Consider modifying the implementation plan to allow years for 10%, 5 years for 25%, 7 years for 50%, 9 years for 75%, and 11 years for 100% model verification due to the fact that a learning curve is involved and many entities have large numbers of units. |
| No |
| 1) Applicability, Section 4: Applicability for PRC-019 and MOD-025 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to be focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their criticality to the system seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where relability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. The individual unit size criterion should match the aggregated plant size criterion. |
| Yes |
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| Yes. R1, Part 1.1.1 needs clarification. We recommend this be revised to state, "Assuming initial steady state system conditions with the AVR in service, verify the limiters…" Reflect any changes in M1. R1, Part 1.1.2 needs clarification. We recommend this be revised to state, "Confirm the settings determined in Part 1.1.1 have been applied to the in-service equipment." Reflect any changes in M1. Some consideration of changing the five year recurring verification of the coordination required by R2 to a six year period should be performed so that typical 18 month and 3 year outage schedules will coincide with the requirement periodicity. In the applicability sections 5.1 and 5.2, we prefer that the percent complete be "of the entities total applicable MVA" rather than "of its applicable Facilities". |
| Individual |
| Thad Ness |
| American Electric Power |
| Yes |
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| Yes |

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| Yes |
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| In section 4.2 for Facilities , the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC. Item 5.3 appears to be one exclusive example. What if there are three wind farm sites? AEP agrees with the example given, but 5.3 should contain a high-level statement followed by the example provided. We still oppose using language requiring that a standard be effective by “the first day of the first calendar quarter” x “calendar years following applicable regulatory approval”. It is not clear exactly how this is to be interpreted. For example, if regulatory approval is granted on Feb 1 2013, is the standard effective on Jan 1 2014 or April 1 2014 if “x” is one year? For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year. |
| No |
| AEP is not certain that load rejection testing would be an acceptable means of verification, particularly given that a unit is disconnected from the system and the issues alluded to in the footnote. Is the drafting team completely confident that this is an appropriate means of verification and could not produce a mischaracterization of unit behavior during system frequency excursions? |
| No |
| The Attachment 1 table is difficult to read, and the information contained could be more clearly conveyed than it currently is. The event triggers and periodicity span across multiple pages, making it a challenge to use effectively. Titling the column “Comments” does not properly describe the information that column contains. Suggest re-naming this column as “Action Required”. Within the section for “Subsequent verification for an existing applicable unit”, it is unnecessary and counter-intuitive to allow the resetting of the period to only occur “within one year of the applicable unit’s ten year anniversary date…”. This should be corrected to state that the verification period could be reset for any frequency excursion occurring “or before the 10 year anniversary date”. Within the “Event Triggering Verification” column (page 16 of the clean version), how is the following combination not non-compliant? “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period” and “Neither an on-line speed governor reference test nor a partial load rejection test was performed”. Attachment 1 has references to "Not required until responsive control mode operation for connected operations is established." AEP does not understand what this statement means. |
| No |
| We can find no mention of "base load units" in Attachment 1 or anywhere in the standard, so it is not clear that those units have indeed been exempted. There needs to be more explicit references and/or parameters with respect to the meaning of "base load units" in the body of the standard rather than an implied |

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| reference in the attachment. We don't know what the SDT believes is a "base load unit"; therefore, we cannot support an exemption. |
| In sections 4.2 Facilities – the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC. In regards to the terms “Load Control” and “Active Power/Frequency Control” used throughout, more than the clarification of footnote 1 seems necessary. Does “load control” refer to turbine and boiler coordinated control? It is our experience that variable energy plants do not regulate active power or frequency. Appropriate models may not exist at the present time for either load control or active power/frequency control. If so, what then? The grammar in the Purpose section could be simplified and made more clear. Should the implementation plan for the effective date of R1 precede the effect date for R3 through R5, by 90 days perhaps? R 2.2: Obtaining an aggregate model would only make sense if the units comprising that aggregate are at least similar if not identical to each other. This needs to be made clear. What happens if units whose response is to be aggregated are not similar? R 2.1.2: It would be beneficial to provide examples for “Type of governor and load control and active power control/frequency control equipment” in perhaps the same manner as MOD-026-1 R2.1.2. This comment form states “The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next.” What is meant by governor response not being consistent from one frequency excursion event to the next? Is this because of deadband or perhaps something else? M2 - it states "... Model was verified and dated evidence of transmission, , such..." we recommend changing the sentence to be "... Model was verified and dated evidence of transmittal, such..." VSL - requirement 5 moderate VSL needs to be changed to say "but less than or equal to 150 calendar days." Also, the "or" statement in that column needs to be changed from "181 calendar days" to "151 calendar days" |
| Yes |
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| Yes |
| On the P-Q diagram, it is not clear how the instantaneous field current and instantaneous field current trip shown in the diagram would be relevant to coordination. These two values are not typically provided in such a diagram. |
| The purpose statement as provided in the standard is not the same as the one stated in this comment form. The VSL for R1 should be graduated. For example, missing one element on a fleet should not be categorized as a severe VSL. Perhaps a system similar to the one (Proposed?) for PRC-005 could be adopted. |
| Individual |
| John Bee |
| Exelon |
| Yes |
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| Yes |
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| Yes |
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| 1) As stated in the previous comments from Exelon to Questions 5, 7, 12, 13 and 14 as documented in the Consideration of Comments on Generator Verification (MOD-025-2) – Project 2007-09 dated 2/22/12 (p81, p106, p150, p156 and p189), Nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. In response to Exelon's comments on Questions 5, 7, and 14 the SDT states that [a nuclear plant] "should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities." In addition, the statement "Auxiliary bus voltage limits should be observed" was added to Note 1 of Attachment 1. As further stated in Summary Consideration for Question 5, the SDT has added Note 4 to Attachment 1 that states that "The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability, or the minimum lagging capability at which it can operate." Exelon requests that this note be further clarified as follows: "The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability or the unit is restricted due to other regulatory, unit stability or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate." In response to Questions 12 and 13 to Exelon's comments, the SDT further states that "Nuclear units are not required to perform Reactive Power verification at minimum Real Power output" as currently stated in Attachment 1 Verification Specification 2.2. Exelon requests this be revised to clearly state that nuclear units should also not be required to perform under-excited (leading) reactive capability verification. Attachment 1 Verification Specification 2.2 should be revised as follows: 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output and are not required to perform under-excited (leading) Reactive Power verification. 2) With respect to all of the Notes provided on the current draft MOD-025 Attachment 1, Exelon requests that the Notes be tied to the verification specification that they are referring to. 3) Historically Exelon has noted that its larger generating units have not been able to attain all of the data necessary for an over-excited full load and minimum load reactive power verification on the same test day due to grid constraints. Please clarify that it is acceptable to perform segments of the reactive power verification on different test days as long as each portion of the test is performed for the required duration. 4) Please explain what is meant by the statement "[T]he recorded Mvar values were adjusted to rated generator voltage, where applicable" in the Summary of Verification section of Attachment 2. 5) The last Section of MOD-025-2 Attachment |

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| 2 requires certain Verification Data to be provided by unit or Facility, as appropriate. Exelon suggests that both the "rated" and "as tested" generator hydrogen pressure values be recorded as a comparison. Suggest the following be added to the Summary of Verification in Attachment 2: • Generator hydrogen pressure (if applicable) Rated pressure: _____________ As tested pressure: _____________ 6) In the Consideration of Comments on Generator Verification (MOD-025-2) – Project 2007-09 dated 2/22/12 (p12), the SDT responded to the industry that it anticipated that Regional Standards would be retired once MOD-025-2 is approved. In addition, the SDT added language specifically to the Implementation plan to address the intent of ReliabilityFirst (RFC) to perform a review of both MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC BOT approval of NERC MOD-025-2. RFC has recently announced that they are “suspending Regional Standards efforts.” On the NERC website MOD-024-RFC-01 is RFC Board Approved and MOD-025-RFC-01 is NERC BOT Adopted. Exelon is unsure of the status of both MOD-024-RFC-01 and MOD-025-RFC-01. With respect to the wording added to the Implementation Plan for MOD-025-2; what is the status of the intended review by RFC of both Regional Standards upon NERC BOT approval of the associated NERC MOD-025-2 Standard? |
| Yes |
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| Yes |
| Exelon appreciates the additional guidance provided in the Unofficial Comment Form for Project 2007-09, "Generator Verification," that includes specific examples for implementation to aid the industry in understanding the proposed model verification periodicity; however, Exelon is concerned that this information will be "lost" since it is only documented in this format. To ensure this guidance is available to registered entities in the future, Exelon suggests that this guidance, including the four examples, be added to the Implementation Plan for MOD-027-1. The staggered implementation period in the current draft of MOD 027-1 and the additional guidance provided by the SDT, seems to imply, as substantiated by the examples provided above, that before the 1st model verification period at T=0 all recorders are required to be installed and ready to trigger in the case of an ambient event for each generating unit. Please clarify that the staggered implementation allows the applicable generating units to modify/install recording equipment at any time during the three year implementation period at the discretion of the Generator Owner and not that all applicable units should have the recording equipment installed and ready to trigger following regulatory approval of MOD-027-1. |
| No |
| As stated in the previous comments from Exelon as documented in the Consideration of Comments on Generator Verification (MOD-027-1) – Project 2007-09 dated 2/23/12 (pp 46-47) the proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure |

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| Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that “Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units...”. The response from the SDT on Exelon's comment was to add an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in control mode, except during normal start up and shut down, that would result in a turbine/governor, and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT further stated that they believe this modification to MOD-027-1 will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode. While Exelon appreciates and agrees with the addition to Attachment 1 (the Periodicity Table) as stated above, Exelon is concerned that this exclusion may not be interpreted uniformly across the Regions or by auditors and therefore suggests that the exclusion be explicit to exempt "base loaded nuclear units that do not respond to grid frequency deviations" and that the exclusion be added to the Applicability section of MOD 027-1. Note that there is no definition in the NERC Glossary of Terms of a "base loaded unit" and in a deregulated environment the term "base loaded unit" is problematic. Therefore Exelon strongly suggests that nuclear units should be explicitly excluded due to the reasons provided above. Exelon suggests addition of the following to the Applicability Section. 4.2.4 Individual base loaded nuclear generating units that do not respond to frequency deviations are exempt from the verification requirements of Standard MOD-027-11 R.2 1Base Load nuclear generating units that do not respond to grid frequency deviations are required to document circumstance for exemption in accordance with Attachment 1 Exelon suggests addition of the following to the Attachment The existing SDT proposed exclusion is as follows: "New or existing applicable unit is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)" Exelon suggests revising as follows: New or existing applicable unit is considered a Base Load nuclear generating unit that is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.) |
| 1) Exelon requests that the Implementation Plan for MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions," add a section to provide guidance on the applicability of Base Loaded nuclear generating units that do not respond to frequency excursion events as explained above. In addition to the exemption criteria, more guidance should be provided on the required "document circumstance with a written statement." 2) MOD-027-1 R5 states that the Transmission Planner is to notify the Generator Owner within 90 calendar days whether the model is "useable" (i.e., meets the criteria specified in Parts 5.1 through 5.3). The usability of the model should be that it mimics the generating unit governor regardless of whether the governor/model challenges transmission operating criteria. The requirement as |

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| written implies that a Transmission Planner could challenge the governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09 (as stated in the SAR) which is "[t]o ensure that generator models accurately reflect the generator's capabilities and operating characteristics." 3) Please clarify what is intended by an "applicable facility" with respect to implementation. Is it the intent that the total population generating units that meet the characteristics in Requirements 4.2.1, 4.2.2 and 4.2.3 start as being "applicable units" for the purposes of implementation and then during the staggered implementation, each individual unit is to be evaluated for verification requirements?. For example, if a Generator Owner had ten units (five of which are nuclear units) each greater than 100 MVA and therefore all meet criteria of 4.2.1 then those ten units are in the scope of MOD-027-1 for implementation. This is regardless of any verification requirements that may then exempt them from verification per Attachment 1? 4) MOD-027-1 R1 is inappropriately prescriptive to Generator Owners (GOs). The Transmission Planner (TP) should merely ask for modeling parameters from a GO and not provide instructions on how to obtain acceptable models used in TP software. GOs may not own such software. 5) MOD-027-1 R2 is unclear as to the intended obligations. The sub-bullets in 2.1 should clearly state that following one or two of the sub-bullets are acceptable. Requiring all sub-bullets is too prescriptive and problematic. In the case of 2.1.1, fossil generating units are not likely to have the equipment necessary to demonstrate compliance. 6) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). 7) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted. |
| Yes |
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| No |
| Exelon does not believe the SDT adequately addressed the concern previously raised by Exelon regarding Section G as documented in the Consideration of Comments on Generator Verification (PRC-019-1) – Project 2007-09 dated 2/22/12 (p 18). The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (page 7) states "[f]or the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current." This conflicts with Requirement R1.1.1 that states "... assuming normal AVR control loop and system steady state operating conditions." Currently the two statements are in conflict with one another in that one requires a "fixed" field current (i.e., AVR in "manual") and the other requires "normal operation" (i.e., AVR in "automatic"). The response given by the SDT was that "[t]he SDT agrees that the generators must normally operate in AVR mode." This does not address the |

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| conflict identified. The SDT needs to allow for automatic mode for AVR to accommodate those generating units that have redundant automatic channels as is the case for newer digital AVRs. This will allow the Generator Owner to use AVRs automatic mode when plotting SSSL. The response given by the SDT was that "[t]he calculation of the SSSL, based on a fixed-field current value, is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex..." Exelon does not believe this response is acceptable. PRC-019-1 should not force a Generator Owner to use the SSSL curve with the AVR in "manual". There should be an option that allows a Generator Owner to use the SSSL curve with the AVR in "manual" or in "auto." If the Generator Owner wants to use a more complex calculation to plot SSSL curve with the AVR in "auto" (which although more complex would also be more accurate) it should be left to the discretion of the Generator Owner. |
| 1) In the Consideration of Comments on Generator Verification (PRC-019-1) – Project 2007-09 dated 2/22/12 (Question 5 on p 57), Exelon requested that the implementation period by 2 years following regulatory approval. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). An implementation period of 2 years will allow for any modifications to existing equipment be completed during a refueling outage. In response to Exelon's comments on Questions 5, the SDT states that "[t]he SDT does not believe the requirement to have 20 percent of applicable units compliant within the first year is an undue burden. For the example noted, the unit could be verified with the last 20 percent of Exelon’s fleet, which gives over four years to comply with the standard." Exelon does not believe that the SDT fully evaluated the example. Exelon Nuclear is registered with NERC in the RFC Region as a GO/GOP. This registration encompasses 16 generating units which are all nuclear generating units. Exelon Nuclear is also registered with NERC in the SERC Region as a GO/GOP. This registration encompasses only one (1) generating unit which is also a nuclear generating unit. Therefore the explanation given by the SDT to move the nuclear "unit" to the last 20 percent of the implementation period is impractical as it would be for any GO/GOP that has a fleet of all nuclear generating units. 2) PRC-019-1 R1 (or the Applicability section of the Standard) should not apply to facilities currently in service until changes in the protection system are made. Applying this Standard to facilities in service will be a paperwork burden and will have no impact on reliability. It is more reasonable to apply PRC-019-1 R1 to facilities upon changes to the protection system. 3) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). 4) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted. |
| Individual |

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| Don Jones |
| Texas Reliability Entity |
| Yes |
| R1.2 – We suggest removing the phrase “date the data is recorded for a” and replace with “date of a”. It is not important to note the date on which the data is “recorded” but rather the date a staged test occurred. “Recorded” could have different meanings - is it “recorded” when a Verification Data form or report is finalized internally or when PI Historian captures the SCADA data? Remove “or a form containing the same information as identified in Attachment 2” and change the verbiage on Form 2 (“changes may be made to this form”). If there is a form, require its use to promote consistency. Additional forms can be provided by the TP if needed to cover additional configurations. |
| Yes |
| Attachment 1, item 3.2: Is there a requirement for a voltage schedule for a synchronous condenser? Also, if there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. Attachment 2 does not necessarily include Synchronous Condensers. |
| Yes |
| |
| 1)Facilities--Avoid use of “bulk power system.” There is inconsistency between the Standards in this Project with regard to applicable Facilities. Suggest using BES definitions or Transmission Planner requirements (if TP requirements are inclusive of BES as a minimum). 2)Effective date 5.3: ”Wind site” is not defined. 3)Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning models for specific periods. 4)It is unclear whether this Standard requires Gross or Net (or both) capabilities to be verified. The Attachments seem to allow for either, to some degree, but is not definitive. It should be clearly stated which is expected. The following comments refer to the Attachment 1: 5)In Attachment 1 the term “commercial operation date” is used. The phrase should be more along the lines of “initial synchronization to grid,” as a commercial operation date may be an extended time from initial synchronization. In general, there would be manufacturer’s data that may be used in models but it is critical to understand the capabilities early on. 6)How does one determine what changes are “expected” to make a 10 percent change in last reported capability? We suggest deleting “is expected to.” 7)Attachment 1 item 2.1: We recommend changing the real/reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. Also, we recommend changing the first sentence as follows: “Verify gross and net Real Power capability, gross and net Reactive Power capability over-excited (lagging) and gross and net Reactive Power capability under-excited (leading)……”. 8)Attachment 1 item 2.2 appears to allow wind and photovoltaic “applicable facilities” to not have to verify Reactive Power capability at a minimum Real Power output. Is that the expectation of the SDT? At least in 2.1 there were statements regarding what was expected of wind and photovoltaic Facilities for Real and Reactive Power at expected maximum Real Power “at time of the verifications.” |

9)Attachment 1 item 2.3: What is the basis for “one continuous hour?” What is the expected value(s) to be provided for the continuous hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and wind turbines may not allow for a full hour. Additionally, system conditions must be taken into effect for tests (disturbances that do not necessarily put the system into an emergency situation but may impact capability). Current ERCOT regional criteria for the Reactive Power leading and lagging tests is 15-minutes. 10)Attachment 1 item 2.4: Is this meant to be an instantaneous value to be collected? Or do the units have to maintain the verified value for an hour? Is the intent of 2.4 captured in 3.1 (as 3.1 appears to be a value recorded at the end of the verification period)? 11)Attachment 1 Section 3 does not include all the measurements shown in Attachment 2. While Form 2 may be changed (hopefully under the direction/guidance of the TP), section 3 should at least capture what measurements are portrayed in the Attachment 2 form as it exists. 12)Attachment 1 item 3.2: This is unclear regarding seasonal expectations and how to capture those expectations in a verification activity. As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. 13)Attachment 1 items 3.3 and 3.6: “Interconnection” should not be capitalized. 14)Attachment 1 item 3.4: Should include “Others as applicable” to match Verification Data form. 15)Attachment 1 item 3.8 is not captured on Verification Data form. 16)Change MVAR to Mvar in the “Notes” section of Attachment 1. Attachment 2 17)The first part of Attachment 2 assumes a single point of interconnection (Point F). Should there just be a requirement to supply a detailed one-line with measurement points noted and remove the sample one-lines? 18)In the Verification Data form, the use of the phrase ”connected at the same bus” may have different interpretations than expected. Suggest removing the phrase or at a minimum changing the phrase to “measured at sites connected to the low side voltage level(s) of the GSU”. It should be noted that Auxiliary and tertiary loads (in terms of Real and Reactive Power) are not necessarily “connected at the same bus.” 19)Why is “N/A” in a few locations on the Verification Data form? 20)Please change the Verification Data form to use the same terms in the definitions of Net Reactive and Net Real Power (form calls for Gross Reactive Power Generating Capability” but definitions of Net do not use same term). VSLs 21)VSLs for R1- Suggest matching the language of the requirement with regard to “date the data is recorded for a staged test” or to the changes suggested for R1 (“date of a” staged test). 22)VSLs for R1- Suggest matching the language of the requirement with regard to “the date of the historical operating data that was selected.” The Requirement states “the date the data is selected for verification using historical operational data” which may be different than the date of the historical operating data (that was selected). 23)VSLs for R1- The second “OR” statement is not auditable if the Verification Data form is allowed to be changed. If the form had a minimum data requirement that had to be provided, a VSL could be created. As written, the statement “The Generator Owner verified the Real Power capability and submitted the data but was missing 1 to 33 percent of

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| the data" and variations thereof cannot be audited. 24)VSLs for R1- Suggest adding "Real Power" in the third and fourth "Or" statements as R1 only refers to Real Power—"The Generator Owner performed the Real Power verification..." 25)Severe VSL for R1- The last "OR" statement needs corrected as it is the same language for the Lower VSL. Suggest changing to the following: "The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months. " 26)R2 VSLs have the same comments as R1 VSL with the exception of adding "Reactive Power" instead of "Real Power" in the suggested locations. 27)R3 VSLs have the same comments as R1 VSL with the exception of adding "Reactive Power" instead of "Real Power" in the suggested locations. Additionally, there are multiple references to "Generator Owner" that should be replaced with "Transmission Owner." |
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| No |
| Only base-loaded units that are nuclear units should be exempted. |
| 1)Applicability: a.Section 4.2: Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements, whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection. The applicable Facility requirements should be the same for each Standard in this Project! b.Section 4.2: We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. c.The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an "applicable unit", then wait until a frequency excursion occurs to measure performance, then has 365 days to send the model data to the Transmission Planner. 2)Effective Dates: a.Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correct model errors that may lead to (or have led to) improper planning of the system based on the current model results. b.For establishment of initial verification period, the MOD-027 Attachment 1 "OR" phrase is inconsistent with the timeframes to be compliant per the effective dates (e.g. If a unit records a response on the "Standard Implementation Effective Date" and then has 365 days to send the data, how can it meet the 25% compliance requirements on the first day of the first calendar quarter three years following regulatory approval?) What is the "Standard Implementation Effective Date". c.The SDT should consider moving the Consideration for Early Compliance criteria from Attachment 1 into the Effective Dates section. 3)R3: The inclusion of "or a plan" extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Do the plants need to disconnect until "usable" data |

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| is provided? 4)R4: The inclusion of “or plans” extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Ddo the plants need to disconnect until “usable” data is provided? 5)VSL R2: The Severe VSL language is different from the Lower, Moderate, and High VSL language regarding the models. Language should be consistent. 6)The following comments relate to Attachment 1: a.R3: The timeframes are too long. If a GO has a unit that the TP had deemed not “usable” it has 90 days to produce a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response—then has another 365 days to send the data to the TP. What does the TP do in the interim? b.R4: The timeframes are too long. If a GO has a unit that undergoes changes to the “turbine/governor and load control and active power/frequency control system” it has 180 days to produce the model data OR a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response—then has another 365 days to send the data to the TP. More time would be needed if the TP took 90 days to verify the model data and possibly 90 more days by the GO to defend the model data, changes or verification plan (per R5 and R3). What does the TP do in the interim? c.Comment column: How do “Comments” get used in an audit? If there is a requirement to transmit information within a certain timeframe, that should be included in the “Verification Periodicity” column and not the “Comments” column. d.Criteria 4: If there are going to be references, give the references a number rather than referring to “4th row in the following table”. |
| Yes |
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| Yes |
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| 1)Purpose: Suggest replacing the phrase “equipment capabilities” with the NERC-defined term “Facility Ratings”. 2)R1.1.1: Suggest breaking this up to make the requirement clear. R1.1 Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility: 1.1.1 Limiters and the Protection System for the applicable Facility are set to allow full capability within the Facility Ratings of the applicable Facility and steady-state Stability Limits; 1.1.2 Limiters are set to operate before the Protection System of the applicable Facility; 1.1.3 The Protection System of the applicable Facility is set to operate, isolate or de-energize equipment, in order to protect equipment from damage when operating conditions exceed Facility Ratings or Stability Limits; 1.1.4 Settings determined in Parts 1.1.1 through 1.1.3 are applied to in-service equipment. 3)R2: Remove the phrase “the existence of” in the first sentence. Recommend re-wording as follows “Each Generator Owner and Transmission Owner shall verify the coordination identified in Requirement R1…..”. 4)R2: Suggest considering removal of the phrase “are expected to” as this is somewhat arbitrary and could lead to differences in application of the Standard. The VSL for R2 has the following phrase “identification or implementation of a change that affected the coordination” that indicates the GO or TO verified ONLY coordination on changes that affected the coordination (rather than what the Requirement states with the phrase “are expected to”). If the phrase “are expected |

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| to" is meant to bolster coordination efforts than the VSL language should address the same concept. 5)R2: Suggest re-wording three bullets as follows (leave 4th bullet unchanged): • Voltage regulating equipment settings or component changes • Generating or synchronous condenser Facility Rating changes • Generating or synchronous condenser step-up transformer Facility Rating changes 6)M1: Suggest replacing the phrase "applicable Facility capabilities" with "applicable Facility Ratings". Also, suggest replacing the word "capabilities" with "Facility Ratings" in the 3rd bullet of M1. 7)VSL R1: Suggest rewording as follows to match the R1 requirement, "The Generator Owner or Transmission Owner failed to coordinate the voltage regulating controls and Protection System settings with the applicable Facility Ratings as specified in Requirement R1." 8)VSL Severe R2: Remove the phrase "the existence of" in both sentences. Recommend re-wording as follows "The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1….." |
| Individual |
| Ed Davis |
| Entergy Services, Inc |
| Yes |
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| Yes |
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| Yes |
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| Yes: • VAR-002-1.1b Requirement R1 states "The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator." However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. Entergy recommends that MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the Entergy recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard. • On Attachment 2 Comment Section for Point A, add note that "individual unit values are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) • On Attachment 1, item 2.6, add sentence stating that "GSU |

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| transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.” If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. • On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. • Entergy recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of “sister unit” concept. This will facilitate more consistent unit verifications. • Entergy agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. Recommend that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar changes which impact the reactive testing results. • Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. |
| Yes |
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| No |
| Regarding the terminology in Attachment 1, “Turbine/governor and load control and active power/frequency control”, should all the “and”s in the Event Triggering Verification column be “or”s? Entergy recommends that this be reviewed for consistency. |
| No |
| Entergy sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification. |
| Entergy found this excerpt (section 4.2.1 bullet 2) below to be confusing, particularly the second sub-bullet below: • For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating); and o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings Could the |

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| SDT provide some examples of how this would work? Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability. |
| Yes |
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| Yes |
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| There needs to be a requirement that the GO protection coordinate with the steady state stability limit. Entergy recommends inserting “or reach steady state stability limits” after “equipment” in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions. Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Entergy recommend that you stay with a 30 day increment. Also in R2 you need a space between “5years”. |
| Group |
| FirstEnergy |
| Sam Ciccone |
| FirstEnergy Corp. |
| Yes |
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| Yes |
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| Yes |
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| FirstEnergy has the following comments related to Attachments 1 and 2: 1. Att. 1 Sec. 2 – We suggest replacing the phrase “that demonstrated at least 50 percent of the capability of the associated D-curve” with “that demonstrated the maximum capability of the associated D-curve”. In addition, we suggest language as follows: “The reason(s) for any verified Reactive Power capabilities that, due to plant equipment, are more constraining than the appropriate generator Reactive Power capability curve (D-curve) shall be documented. (For example, exciter or generator field current limitations, generator terminal voltage, auxiliary or safety-related bus voltage limitations, volts per Hz alarms, excessive generator vibration, generator temperature limits, hydrogen coolers restrictions, shorted rotor turns, safety, other protection, etc.) 2. Att. 1 Sec. 3.4 – Although we understand the drafting team does not want to be prescriptive and dictate an ambient temperature methodology, we believe the requirement is too broad and up for much interpretation across entities and regional auditors. There should be a more standardized method of determining the ambient adjustment for consistency, for example something similar to RFC standard MOD-024-RFC-01 Requirement R4.3. 3. We suggest adding the following or similar wording in the standard when a verification cannot be |

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| completed due to operational issues and include the allowance of engineering analysis to complete the verification: “1.2.3 If a verification test has been started and cannot be completed due to a transmission system limit or condition, this transmission system limit or condition shall be documented, and engineering analysis taking into account known limitations shall be used to determine the verified capabilities.” |
| Yes |
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| FE offers the following comments and suggestions: 1. We are concerned that a regional or interconnection-wide excursion from the scheduled frequency may impact potentially an entity’s entire generation fleet and the time frame of 365 days per R2 and Att. 1 may not be feasible. We ask the team to take this into consideration and add more time for these scenarios. 2. Disturbance Monitoring Equipment (DME) necessary to obtain recorded data from excursions may be owned by the Transmission Owner and not the Generator Owner. The team may also want to consider how this MOD-027-1 standard is coordinated with the NERC PRC-002 DME standard that is still in development. |
| Yes |
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| Yes |
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| R1 – The term “In-service” should not be capitalized |
| Individual |
| Matthew Pacobit |
| AECI |
| No |
| I belive that a one continuous hour test for reactive testing will not increase reliablity. Most units are not used for long periods of time for reactive power. I am also worried about damage do to High winding tempetures during this test. |
| Yes |
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| Yes |
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| Yes |
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| Yes |
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| Yes |
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| No |
| I Believe that the Ratting should be 100 MVA for all Generating units |
| Yes |
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| Group |
| PacifiCorp |
| Sandra Shaffer |
| PacifiCorp |
| Yes |
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| Yes |
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| Yes |
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| Yes. See below: PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.1 of the "Applicability" section (as well as to sections 4.2.2 and 4.2.3). The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence would reads as follows: "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to Section 4.2.2 and 4.2.3. |
| Yes |
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| Yes |
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| Yes |
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| Yes. See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of 4.2 - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for the first bullet under section 4.2.2): "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made throughout section 4.2 where applicable. 2. PacifiCorp believes that the sub-bullets of the second bullet under Section 4.2.2 of the "Applicability" section (and elsewhere, as applicable) introduce confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following |

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| language to replace the two existing sub-bullets under the second bullet of section 4.2.2: • "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and • Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows: "For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5." |
| Yes |
| |
| Yes |
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| Yes. See below: 1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of Section 4.2. - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for section 4.2.1): "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to section 4.2.2 and 4.2.3. |
| Group |
| SERC Planning Standards Subcommittee |
| Charles W. Long |
| Entergy Services, Inc. |
| Yes |
| |
| Yes |
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| Yes |
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| * Change references to “bulk power system” in the Applicability section to “Bulk Electric System.” * VSL’s for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33. * VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from “more than 12 calendar months but less than or equal to 13 calendar months” to “greater than 15 calendar months.” * Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50 |

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| percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word “reactive” be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." * Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. * Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires..." |
| Please check footnote numbering. Footnote 5 in the redline version is labeled footnote 4 in the clean version. |
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| The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers” |
| Group |
| Florida Municipal Power Agency |
| Frank Gaffney |
| Florida Municipal Power Agency |
| |
| No |
| FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards) To parallel the Section 215 definition of BPS at (a)(1) "The term \`bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..." We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is |

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| that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn’t already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard. |
| Yes |
| See comments to question 2 |
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| |
| No |
| The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? We recommend numbering the rows in the table so that row references are clear. |
| No |
| As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly. |
| See response to Question 2 regarding the improper use of the term bulk power system |
| No |
| See response to Question 2 |
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| |
| Individual |
| Randall McCamish |
| City of Vero |

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| No |
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| No |
| FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards) To parallel the Section 215 definition of BPS at (a)(1) "The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..." We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn’t already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard. |
| Yes |
| See comments to question 2 |
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| |
| No |
| The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the |

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| next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? We recommend numbering the rows in the table so that row references are clear. |
| No |
| As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly. |
| See response to Question 2 regarding the improper use of the term bulk power syst |
| No |
| See response to Question 2 |
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| Group |
| PPL |
| Annette M. Bannon |
| PPL Generation, LLC |
| No |
| Suggest changing “Intended” to “preferred” in the Att. 1 statement, “It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.” |
| Yes |
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| Yes |
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| Comments: a. A reference to power factor is needed in para. 2 of the Att.1 verification specification statement, “at least 50 percent of the capability shown on the associated D-curve.” Is this criterion intended to apply at 1.0 PF? b. Para. 2.1 of the verification specification in Att.1 is unclear in citing, “normal (not emergency) expected maximum Real Power.” Normal operating level is typically not the maximum of which a unit is capable. Suggest this test-to generation be changed to, “normal full-load Real Power,” defined as the output at which the unit usually runs for the ambient conditions existing at the time of the verification. c. Add, “for the conditions existing at the time of the verification,” at the end of the first sentence of para. 2.2 in the verification specification in Att.1. d. Change “collect” to “correct for” in verification specification para. 2.6 in Att.1. e. The statement, “The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions,” in para. 3.4 of the verification specification of Att.1 is not clear. Possibly an “if” was intended before “the Generator Owner.” A reference condition is also needed, or instructions for identifying the correct-to criteria, if the as-tested normal real power is to be adjusted for ambient conditions. Such correction often does not apply for the purposes of this standard, however. A fossil |

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| unit with an emergency max capability of 750 MW on a 90 F day can achieve higher output at 60 F, for example, but the normal output may be 725 MW regardless of ambient conditions (see comments above). f. Add, “Transformer Real and Reactive Power losses will also be estimates or calculations,” to para. 4.1 in the verification specification of Att.1, as well as the statement, “Only output data are required when using a computer program to calculate losses or loads.” g. Note 2 the verification specification of Att.1 states, “While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification.” It is unclear who supposed to undertake such analyses and how they could be performed. Suggest this note be clarified or dropped. h. The purpose of having a MOD-025 standard is undercut by the statement in Note 4 of the verification specification in Att.1 that “The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.” It is unclear why these tests should be performed if the results aren’t used? Could MOD-025-2 be withdrawn in light of FERC’s March 15, 2012 FFT Order to propose specific standards or requirements that should either be revised or removed due to having little effect on reliability or because of compliance burdens. i. Add “Reactive Power” between “unit’s” and “capabilities” in Note 4 of the verification specification in Att.1. j. It appears that the aux and net values requested in Att.2 are intended to be low-side readings, in which case they should be so-identified. k. Delete from Att.2 the statement, “The recorded Mvar values were adjusted to rated generator voltage, where applicable.” Such adjustments may have unsuitably high uncertainty. |
| No |
| Comments: a. The referenced footnote is number 4, not 5. R2.1.1 and the verification table later in the standard allow the alternative of an on-line speed governor reference change test. In any event the standard requires that, if a naturally-occurring disturbance meeting Criterion 1 does not occur within the specified ambient-monitoring period, we must create one. We are opposed to making it mandatory that GOs conduct such testing. An on-line speed governor reference change test is not always possible. Where it is possible there is risk of creating a larger-than-desired disturbance, possibly threatening grid stability or tripping the generation unit. At the very least there would be a shock to the equipment and some loss of life. The same applies for a partial load-rejection test. It is meanwhile unclear how invasive such episodes would be. Power Technologies, in their paper “Testing Methods, An Overview,” states that five episodes may be required. These are expected to be hard trips, in which case the data gathered may be less useful than the GVSDT is expecting. Rejection to house load, followed by rapid re-synchronization, cannot be expected because need to avoid overspeed due to full-load rejections requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. This is an unreasonable burden to place on GOs, especially when there has not been any commensurate reliability benefit identified. The rationale in MOD-027-1, “to ensure modeling data is accurate,” is far from compelling, nor is it explained why the accuracy of our present, OEM-generated data should not be equal-to or better than |

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| that identified via testing. b. The response adjustment described in footnote 4 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide high-speed recordings of responses to grid disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is there any purpose to making GOs develop models or en masse hire consultants to do so. |
| No |
| We must wait for naturally-occurring disturbances, if not creating upsets of our own, making it impossible to guarantee up-front that the 25%-3 yrs, 50% - 5 yrs etc requirements will be met. Such requirements also conflict with the instruction in the periodicity table to, “Record unit Real Power response to the first frequency excursion event that meets Criteria 1 on or after the Standard Implementation Effective Date.” The row in the same table for, “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period, and neither an on-line speed governor reference test nor a partial load rejection test was performed,” meanwhile appears to pertain to circumstances that are not permitted by this standard. |
| No |
| We do not see in MOD-027-1 any language that defines baseloaded units as being verified and consequently exempts them from testing. It is true that a gas turbine running at the OEM-established baseload firing temperature is maxed-out and will therefore not exhibit any response to a frequency dip, but it is unclear what units are “always base-loaded.” We also do not see any suitable definition of the term, “base loaded unit.” The NERC Glossary defines “Base Load” as, “The minimum amount of electric power delivered or required over a given period at a constant rate;” but so-called baseloaded units may not run at a constant rate, instead often cycle between full output and minimum load on a daily basis. |
| Comments; a. The comparison of actual and expected response in R2.1.1 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide also high-speed recordings of responses to grid-disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is clear that there any purpose to making GOs do so. b. R1 should state that generation equipment OEM models are acceptable. This is the source of information we presently have for representing the dynamic response of our equipment. It is probably also the best source of data possible. |
| Yes |
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| No |
| The draft standard is technically sound, but additional clarity may be needed to enforce it in a uniform and unambiguous fashion. The GVSDT should list in section G all relays and associated excitation system and voltage regulator functions that, if present and active, are covered by this standard. |
| Comments: a. Change “capabilities” in the third bull-dot under M1 to “ratings.” b. Having limits set before trips, and trips before damage, is a necessary part of the generation plant design process, so the requirements of the proposed standard in |

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| this respect are just business as usual. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in GO possession. We suggest that PRC-019 be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. |
| Group |
| Transmission Access Policy Study Group |
| William Gallagher |
| Transmission Access Policy Study Group (please see www.tapsgroup.org for a list of TAPS' more than 40 members) |
| |
| No |
| The SDT states that it “felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry Criteria and the BES definition.” TAPS agrees that the standard should be consistent with the BES definition. Given that the MVA limits in the BES definition (and the Registry Criteria) may change, TAPS believes that the standard should not contain numerical limits. Moreover, the standard should be based on the BES definition, which delineates the elements subject to Reliability Standards, rather than on the Statement of Compliance Registry Criteria, which instead defines the entities that must comply with Reliability Standards. We believe that the SDT’s concern about synchronous condensers can also be addressed more effectively without incorporating text from the current Registry Criteria. TAPS therefore suggests that the Applicable Facilities section be revised as follows: “For the purpose of this standard, the term, ‘applicable Facility’ shall mean ‘BES generator,’ except that a generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator’s restoration plan is not an applicable Facility for the purpose of this standard. For the purpose of this standard, a synchronous condenser is treated as a generator.” |
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| As stated with respect to MOD-025 in TAPS response to Question 2 above, the Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of MOD-027 be revised as follows (note that we have suggested no changes to section 4.2.3 because TAPS has not investigated the relevant conditions in ERCOT): “For the purpose of this standard, the term ‘applicable Facility’ is considered, ‘applicable units.’ Units or plants with an average capacity factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following: 4.2.1 BES generating units/plants connected to the Eastern or Quebec Interconnections with |

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| the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 100 MVA (gross nameplate rating). 4.2.2 BES generating units/plants connected to the Western Interconnection with the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 75 MVA (gross nameplate rating). ... A generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator's restoration plan is not an applicable Facility for the purpose of this standard." |
| No |
| As stated with respect to MOD-025 in TAPS response to Question 2 above, the Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of PRC-019 be revised as follows: "For the purpose of this standard, the term, 'applicable Facility' shall mean 'BES generator.' For the purpose of this standard, a synchronous condenser is treated as a generator." |
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| Individual |
| Greg Rowland |
| Duke Energy |
| Yes |
| However, see our response to Question #4. |
| Yes |
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| Yes |
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| • R1 requires the Generator Owner to verify Real Power capability per Attachment 1, and submit the data per Attachment 2. While Section 3.4 of Attachment 1 requires collection of ambient condition measurements needed to perform corrections to Real Power for different ambient conditions, MOD-025-2 doesn't require that the Generator Owner make corrections for specific conditions (such as summer peak day, etc.), and also doesn't provide for the Transmission Planner to request verification for any conditions other than whatever conditions existed during the verification required by this standard. Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that's not included in R1, Attachment 1 or Attachment 2. MOD-025-2 should either specify the conditions for which the Generator Owner must make corrections to real power, or should require the GO to make corrections to any conditions when specified/requested by the TP/TOP. A requirement should be added for the Generator Owner to provide the Transmission Planner with verification of Real Power capability for different ambient conditions within 90 days of a request by the Transmission Planner. • R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and |

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| Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which engineering analysis is required for model verification. SERC developed a generator model validation guide in ~ 2004, which laid out a process where an engineering review and operating data should be performed first and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the region's planning and generator operators. • Attachment 2, Summary of Verification – Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) • Applicability Section – change "bulk power system" to "BES". |
| Yes |
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| No |
| The Eastern Interconnection frequency excursion criteria of greater than or equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don't provide data that is nearly as meaningful as excursions at 0.06 or 0.07. |
| No |
| Where in this standard is this exemption for base load units? Regardless, base load units do exhibit some response, and the data collection is not difficult to accomplish. |
| • Applicability Section 4.2 Facilities - Need to specify "net" or "gross" capacity factor for the calculation. • R2, 2.2 – Insert the phrase "or individual unit" after the word "aggregate". |
| No |
| • Comments: We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. • Sections 4.2.1, 4.2.2, 4.2.3 – replace "bulk power system" with "Bulk Electric System (BES)". |
| Yes |
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| Individual |
| Michael Goggin |

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| American Wind Energy Association |
| Yes |
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| Yes |
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| Yes |
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| Overall, the draft standard is well-drafted and well help to improve reliability, and I would like to see it pass this round of balloting. If there is another round of revisions to this draft standard, it may make sense to look at this recently added section to make sure that it is a workable requirement for all wind projects: “If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold.” For some wind plants, it may be difficult to schedule a test or retest at a time when 90% of the wind turbines are producing. Some wind plants may have significant periods of time when they have fewer than 90% of their wind turbines producing for reasons beyond their control (wind resource availability), and it is typically not possible to predict when those time periods will occur more than a day or two in advance. Repeated attempts at retests until one coincides with a period of sufficient wind resources may not be the most efficient process for testing a plant. Obtaining additional input from wind plant owners would help to clarify this issue, and if that input indicates a concern, the drafting team may want to change the 90% threshold or provide additional flexibility in the testing process to ensure that this standard will be workable for all wind projects. |
| Yes |
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| Yes |
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| Yes |
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| Individual |
| Scott Berry |
| Indiana Municipal Power Agency |
| Yes |
| |
| no comment |

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| no comment |
| 1)Under 4.2 Facilities, IMPA recommends replacing bulk power system with Bulk Electric System which is used in NERC Standards. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)M1 states that the Generator Owner will have evidence that it submitted a correction for ambient conditions. In requirement 1, it does not state that the Generator Owner shall submit a correction for ambient conditions. Either requirement 1 or Measure 1 needs to be corrected to the intent of the SDT. 3)While realizing that the field or armature may be the limiting component in certain segments of the a generator's capability curve, IMPA does not see any value in making a generating unit verify its under-excited Reactive Power capability and over-excited Reactive Power capability at minimum Real Power. Operation at these points at minimum Real Power will seldom if ever happen. IMPA recommends deleting the requirements for reactive capability at minimum Real Power. 4)When at maximum Real Power, it is not clear what over-excited Reactive Power level a generating unit is to maintain for an hour when at maximum Real Power to constitute an acceptable test. IMPA believes in many instances units will reach a limit, such as volts per hertz, and will not be able to reach the over-excited reactive power curve. A Reactive Power test should be acceptable as long as it stays at a documented, reached limit for an hour and should not be required to retest within 6 months. IMPA recommends that the SDT makes its intent clear on what constitutes an acceptable test when at maximum Real Power and over-excited Reactive Power capability. |
| No comment |
| No comment |
| No comment |
| 1)In section 4.2. under Facilities, IMPA recommends changing bulk power system to Bulk Electric System. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)IMPA supports the use of average capacity factor in the Facilities section of the standard. |
| No comment |
| No comment |
| 1)In section 4.2. Facilities, IMPA recommends using Bulk Electric System instead of bulk power system. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2) IMPA believes that this standard does not increase the reliability of the Bulk Electric System and tends to be an expensive and administrative burden to smaller entities. In addition, IMPA does not see how this standard is a performance based standard which NERC determined to be the course of the future for reliability standards. IMPA believes that the industry does not need this standard. 3) IMPA does not understand why this needs to be performed once every five years if none of the equipment has been changed. |
| Group |
| ACES Power Standards Collaborators |
| Jason Marshall |
| ACES Power |
| No |

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| While we agree with the intent, we believe that Parts 1.2 and 2.2 collectively limit the tests to be no further than 90 days apart. Both parts state that Attachment 2 or another form that contains the same information must be completed within 90 calendar days of the staged test or date the operational data is selected. Since both have real and reactive power entries, can the form be considered completed without both sets of data? If the SDT intends for these real and reactive power tests to be completed greater 90 days apart, some additional clarification needs to be made to Part 1.2 and 2.2. Perhaps a note at the beginning of Attachment 2 explaining that MVAr will not be completed for a real power test and MVA will not be completed for a reactive power test will be sufficient. |
| No |
| While we agree to limit the inclusion of synchronous condensers to 20 MVA, we disagree with two other aspects of the applicability. We disagree with inclusion of Blackstart Resources and applicability to the bulk power system. Blackstart Resources should not be included within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, the purpose of their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during the restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies that standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities |

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| that are or are not material to the reliability of the bulk power system. We also find section 5.3 regarding wind farm verification confusing. What is its purpose? What if a wind farm has more than two sites? Why is it specific to a single technology? |
| Yes |
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| We disagree with testing a unit with capability to operate in synchronous condenser mode in that mode. Most likely the unit would only operate in this mode in an emergency situation. Thus, it does not make sense to operate a unit in an emergency mode for a test. We do not agree with adding a last verification data column in Attachment. This only causes confusion. Will it be clear to auditors that the last verification data column is to remain blank for the initial verification or will we end up with a similar situation to the Protection System Maintenance and Testing standard where auditors required evidence from before the enforcement date of standards? Ultimately, the NERC CEO had to overrule this situation. Furthermore, it creates additional work to transfer data from a previous verification test to the current test when the past sheet could simply be retained. Finally, it causes confusion with the data retention section because the data behind Attachment 2 must be retained. Is this intended to be only the latest verification or does it include the last verification? Item 2 of the verification specifications for applicable Facilities in Attachment 1 conflicts with Parts 1.2, 2.2, and 3.2 of the Requirements R1, R2 and R3. The attachment states that historical data going back two years can be used. However, the requirement parts state that the data must be submitted with 90 days to the Transmission Planner. That would appear to limit the historical data to 90 days. The attachment never makes it clear if you can switch between operational data and staged verification from one test to another. The confusion is caused by the separate listing of periodicities in items 1 and 2 under the “Periodicity for conducting a new verification” section. A close reading of the two items shows they are identical but listed separately to make the statement about listing the “earliest date of those dates” for the operational data. We suggest combining item 1 and 2 together will help eliminate this confusion. We disagree with the need to conduct another staged test rather than using operational data as specified in Attachment I subsection 2 in the “Verification specifications for applicable Facilities:” section. If operational data can be used to satisfactorily verify the unit’s real and reactive power output, it should always be allowed to avoid the need for a staged test. |
| Yes |
| We are assuming the question really intended to reference footnote 4. |
| No |
| We appreciate the examples and believe they go a long way towards highlighting the drafting team’s intent. However, we do not believe the examples are consistent with the requirements. We agree the examples are how the requirements should be implemented but we simply believe they have not documented the requirements in a way that is consistent with the examples. The first example does not seem to be completely consistent with the standard and also contradicts itself. For instance, the language in Row 2 of the table in Attachment 1 states that the subsequent verification must occur within one year of the applicable unit’s ten year anniversary |

of the previous collection date. This could be interpreted meaning it must occur between year 9 and 11. However, the example states (in the sixth sentence) that it must occur after the “10-year period” but then later on (in the eighth sentence) states that monitoring must begin for suitable events must begin “one year before the unit’s 10-year anniversary date of the collection” of data per the Periodicity Table. Nothing in the table says anything about beginning monitoring. Furthermore, it does not make sense to limit a Generator Owner to monitoring for events within one year data collection anniversary date. A Generator Owner should be free to collect data at more frequent periodicities. If they choose to update the model based on these periodicities, the “clock” for subsequent verifications should be reset. The standard should only require that the data is collected and model verified by the given date. The example also seems to support the idea that “within one year” in the table is intended to be 9 to 11 years given that the subsequent data collection occurs between Years 10 and 11. We support the concept of beginning monitoring in year 9 for the second example but believe the standard language as written does not support this concept. As a result, example 2 would appear to represent a compliance violation. Row 2 in the table in attachment 1 states “Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit’s ten year anniversary” or to perform an “on-line speed governor reference change test or partial load rejection test”. It does not say to begin monitoring. It is unequivocal that the subsequent test must occur within 11 years given the language. We suggest updating the table language to clarify that an entity must be begin monitoring for frequency excursion events in Year 9 but one may not be recorded until well after 10-year anniversary (including more than a year). Example 4 helps highlight the issues of the language in the standard. Row 6 requires the Generator Owner to record the “first frequency excursion event that meets Criteria 1”. Row 2 of the table requires that a frequency excursion event that meets Criteria 1 must be recorded “within one year of the of the applicable unit’s ten year anniversary date”. From row 6 and the examples, it would appear the drafting team intended this to begin monitoring within one year to record the first frequency excursion event that meets Criteria 1. We agree with this concept and suggest modifying row 2 language to: “Record unit Real Power response for first frequency excursion event that meets Criteria 1 no later than the ninth anniversary date of the collection of the recorded unit Real Power response used for current validation.” This language will clarify that an event earlier than the ninth anniversary may be used and also clarify that first frequency event after the ninth anniversary must be used (if an earlier event is not voluntarily used) without limiting that the event must occur within Years 9 and 11. We also believe the examples should be added to the standard as an attachment. Otherwise, they will not be part of the standard and the drafting team’s intent could be lost to an auditor. We are concerned that much of the “Or” language in the Periodicity Table regarding waiting to observe a frequency excursion or perform an on-line speed governor reference change test or partial load rejection test could be interpreted as requiring one of these two tests if a frequency excursion is not observed within the appropriate time frame. We believe the language needs to be clarified that a Generator Owner is not required to stage a test if no frequency excursion event is observed.

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| No |
| Conceptually, we agree with the concept of an exemption. However, it is not clear to us where this exemption is located within the standard and how it would even apply. Given the penetration of large amounts of wind and record low natural gas prices, many units that might traditionally be based load might actually operate below the maximum capabilities frequently. Our first question then, is what does it mean to be based loaded and what units qualify? Second, what does an exemption mean? Does it mean that a frequency excursion does not have to be observed or an on-line speed governor reference change test or partial load rejection test does not have to be performed? If so, does a model still have to be provided? Any exemption must be explicitly clear to avoid ambiguity and to ensure that auditors will interpret the exemption in the same manner as registered entities. |
| We believe that this standard is overly administrative by memorializing the interactions between the Generator Owner and Transmission Planner that occur to model the generator's turbine/governor and load control and active power/frequency control systems. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. The FFT process represents one such effort to eliminate these backlogs. Interestingly, within the approval order for FFT, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard. Requirement R3 allows a Generator Operator to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems can be left unsolved. It should be struck. We are not convinced Requirement R4 is needed. The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of applicable control system changes. In the first bullet under Requirement R3, we suggest referencing Requirement R5 regarding "useable" to make it clear that useable is in essence defined in Requirement R5. Otherwise, the reader may not realize that Requirement R5 sets the parameters on what "useable" is. We do not believe simply putting useable in quotes is enough. The numbering of the section 4.2 is not consistent with the parallel MOD-026-1 standard. MOD-026-1 uses numbers for each sub-section while this standard uses primarily bullets. It would be easier to reference and comment if numbers are used rather than bullets and would be consistent. The second bullets of Sections 4.2.1, 4.2.2, and 4.2.3 are confusing and potentially contradictory. First, these sections state that they apply to each |

generating plant/Facility greater than 100, 75 and 75 MVA respectively. Then, the second sub-bullet (under the second bullet) applies to generating plant/Facility. How can there be a plant within a plant? With the first sub-bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 75 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for individual generating units than first main bullets which apply to individual generating units. For example, the first main bullet in section 4.2.2 applies a 75 MVA threshold to an individual generating unit and then second sub-bullet applies a 20 MVA threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. The NERC Glossary of Terms uses a generator as an example of a Facility. In the second sub-bullet, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. The first main bullet under section 4.2.3 in the Facility section uses 50 MVA while the second bullet uses 75 MVA. This is not consistent with section 4.2.1 and 4.2.2 which use the same value for both bullets. Is this intentional? The purpose statement appears to have an extra “that”. It begins with “that accurately represent” and is in the second to last line. Part 2.1 includes an ambiguous statement about using a model that is acceptable to the Transmission Planner. We assume the intent was for the Generator Owner to use a model identified by the Transmission Planner in Requirement R1. If so, we suggest changing “acceptable to the Transmission Planner” to “identified in Requirement R1”. Otherwise, the Generator Owner may be compelled contact the Transmission Planner for an attestation that the model is acceptable. This further ensures that everyone (registered entity and auditors) interprets that language to mean those models identified in Requirement R1. We appreciate the drafting team’s consideration in Attachment 1 to allow a unit that has already verified its turbine/governor and load control and active power/frequency control models to be considered compliant. However, it is not clear how this helps. How does the Generator Owner demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff be sufficient? Will the regional entities be willing to validate that they have confirmed regional criteria? We do not believe the VRF Requirement R5 should have a Medium VRF. It is an administrative requirement that is focused on notifying the Generator Owner as to the suitability of the model they provided. All of the measurements use language that sounds like a requirement and is not consistent with language used in any other NERC standard. They all use “must include”. It is more typical to use “shall demonstrate”, “shall make available”, etc. These measurements should be made consistent with other NERC standards. All of the measurements use language that requires proof of transmission of the communication. Some examples of the proof include data postal receipts, dated confirmation of facsimile, etc. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was

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| transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. Reports on email failures are separate reports. The Compliance Enforcement Authority section is not the latest approved language being used by NERC. We question the need to retain the “latest and previous turbine/governor and load control and active power/frequency control system model verification” as it seems excessive evidence retention. This could require Generator Owner’s to retain evidence for greater than twenty years which greatly exceeds the six-year audit cycle. Thus, it would not even be reviewable in an audit per the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Given that the cycle for compliance exceeds the audit cycle for Generator Owners of six years, we think the drafting team should work with NERC compliance to consider how the auditing of the standard will occur. Some small entities will have audits in which no generator will have to be verified. Should this requirement even be actively monitored or should it only require proof of compliance during investigations? We have identified several issues with the periodicity table in Attachment. First, the table is referred to as the periodicity table in the examples that accompany the unofficial comment form. It is not titled as such in the actual document. We believe a title would be appropriate for clarity. Second, Row 4 is not really a triggering event as the first column describes but rather a set of conditions that allow a Generator Owner to utilize an already verified unit model for a similar unit. Third, as written Row 5 only will apply when non-compliance occurs. For instance, Row 5 only applies when the 11 year period (10 year plus one year grace period) for Row 1 or Row 2 has been violated. We agree with the concept of that Row 5 presents in that a frequency event may not have occurred but the other Rows need to be clarified so that it does not present a non-compliance. Fourth, the first part of row 10 is also not really a triggering event but an exception. |
| No |
| We disagree with the need to include Blackstart Resources within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during a restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power |

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| system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies the standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. |
| Yes |
| We believe it is reasonable to include examples of satisfactory evidence. It helps to highlight the intent of the drafting team. |
| We do not believe Requirement R2 as written accomplishes the reliability purpose. Isn’t the purpose of R2 to compel registered entities to re-verify coordination every five years along with changes to “systems, equipment or setting changes” within 90 days? We do not believe “shall verify the existence of coordination” accomplishes this. We believe that it only compels the registered entity to verify the coordination was performed at some point. It does not compel the entity to verify that coordination reflects current conditions such as Protection System settings. We suggest changing “shall verify the existence of coordination” to “shall coordinate”. Furthermore, we think some of the confusion could be eliminated by including the five-year periodicity in Requirement R1 and focusing Requirement R2 on system and equipment changes. Section D.1.1 needs to be updated to reflect that latest approved language for the Compliance Enforcement Authority. The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the “verify the existence of the coordination” from Requirement R2. Requirement R1 uses “shall coordinate”. We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements 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 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 |

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| this to a High VRF. |
| Group |
| Puget Sound Energy |
| Tom Flynn |
| Puget Sound Energy |
| Yes |
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| Yes |
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| Yes |
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| Very rarely will you get to the capability curve when testing real and reactive power. There is almost always a protective limit or you exceed 105% voltage. NERC does not specify what will prevent you from reaching maximum VAR output, so we assume that is up to the testing engineer. |
| Yes |
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| No |
| This periodicity would ideally be the same as MOD 25 and MOD 26 since this testing, at least in the WECC region, is all done at the same time. Also it is not clear to find the ten year re-test requirement in Attachment 1, in fact it just seems inferred. If it is a ten year re-testing requirement, it should be more clearly stated in one of the requirements. |
| Yes |
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| None |
| Yes |
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| Yes |
| |
| None |
| Individual |
| Ken Wofford |
| Georgia Transmission Corporation |
| Yes |
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| Yes |
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| Yes |
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| No |

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| Why not model what was tested? |
| No |
| We agree with the SERC DRS that the terminology in Attachment 1 be reviewed for consistency. Should the "and's" be "or's"? ("Turbine/governor and load control and active power/frequency control") |
| No |
| This is a MOD 25 question |
| Some of the requirements within this standard are confusing. |
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| |
| Group |
| Western Electricity Coordinating Council |
| Steve Rueckert |
| WECC |
| Yes |
| |
| Yes |
| |
| Yes |
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| Measure M1 specifically references corrections for ambient conditions as part of the evidence required, but Requirement R1 does not specifically call out corrections for ambient conditions. The only reference to corrections for ambient condistions is in Attachment 1. For consistency it seems the Requirement detail and the Measure detail should be the same. The Lower and Moderate VSLs for R1 both include missing 33 percent of the data in the condition identified after the first OR in the VSL. If an entity was missing exactly 33 percent of the required data, it would not be possible to identify an appropriate VSL. WECC Staff recommends the use of the identifiers "less than or equal to" and "more than" to resolve the issue, and recommends that clarification be extended to the rest of this section of the VSLs for R1. The section of the VSLs for R3 that use percentages as the identifier should use "more than" and "less than or equal to" qualifiers. |
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| The purpose statement appears to have an unnecessary word "that" immediately preceding the word accurately. After discussions with members of the drafting team WECC staff understands that the intent of the sub-sub-bullets in the applicability sections is intended to require that individual units greater than 20 MVA at generating plants greater than the identified Interconnection minimum be represented individually, while units less than 20 MVA at generating plants greater than the identified Interconnection minimum be represented as an equivalent, but |

WECC staff does not believe that intent is clearly reflected in the words in the sub-sub bullets. The sub-sub bullets in the applicability section use both “consisting of” (4.2.1) and “comprised of” (4.2.3) and use “consisting comprised of” in 4.2.2. The language should be consistent and the grammatical error in 4.2.2 should be corrected. The Severe VSL for R2 includes providing required models more than 90 days late and also includes not providing models. It is not necessary to include the part about not providing models. If models are never provided, they are more than 90 days late. The VSLs for R5 should use “less than or equal to” rather than just “less than” in the sections identifying how many days late the written response was provided.

**See additional comments received:**

Kansas City Power & Light attached

## Additional Comments Received
## Kansas City Power & Light

1. **The GVSDT has revised MOD-025-2 by splitting Requirement R1 into two requirements that allow for separate testing for real and reactive power. A paragraph was added to the start of Attachment 1 that further explains this point. Do you agree with this revision? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

   Comments:

2. **The GVSDT clarified the applicability of this standard to synchronous condensers greater than 20 MVA (nameplate rating). Do you agree with this applicability? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

   Comments:

3. **The GVSDT clarified that the data is to be submitted to the Transmission Planner by the Generator Owner or Transmission Owner. Do you agree with this? If not, please explain in the comment area below.**

   ☒ Yes

   ☐ No

   Comments:

4. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-025-2?**

   Comments: Should replace “bulk power system” with “Bulk Electric System”. Use of “bulk power system” is ambiguous where as “Bulk Electric System” is fully defined.

5. **The GVSDT has included partial load rejection testing in Part 2.1.1 subject to the conditions specified in footnote 5 (differences between the control mode tested and the final simulation model must be taken into account). Do you agree with the inclusion and footnote 5? If not, please explain in the comment area below.**

   ☒ Yes

☐ No

Comments:

6. **The GVSDT has provided guidance on the periodicity aspects of Attachment 1. Do you agree? If not, please explain in the comment area below.**

   ☒ Yes
   ☐ No
   Comments:

7. **The GVSDT has address units which are always base loaded (by definition a base loaded unit is considered verified). This provides an exemption from verification for base load units. Do you agree? If not, please explain in the comment area below.**

   ☒ Yes
   ☐ No
   Comments:

8. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding MOD-027-1?**

   Comments: Should replace "bulk power system" with "Bulk Electric System". Use of "bulk power system" is ambiguous where as "Bulk Electric System" is fully defined.

9. **The GVSDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 20 MVA. The standard applies to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 20MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the comment area below.**

   ☒ Yes
   ☐ No
   Comments:

10. **The GVSDT revised section G based on stakeholders' comments to provide clarity and to indicate that the items listed are examples of coordination and that entities may provide "Equivalent tables or other evidence." Do you agree with the revisions to Section G? If not, please explain in the comment area below.**

    ☐ Yes

☒ No

Comments: This assumes that the auditor will have the protection skills and knowledge necessary to confirm that "other evidence" is equivalent to the plots shown in the attachment one examples.

11. **Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-019-1?**

Comments: Applicability section states any generator regardless of size that is a black start resource. This standard should not be applicable to black start diesel generators.
R2 requires verification every five years. This standard should only require initial verification during the five year implementation period. After the initial verification, no further verification should be required unless system or equipment changes dictate the need to make setting changes and re-verify.