Individual or group. (72 Responses)
Name (45 Responses)
Organization (45 Responses)
Group Name (27 Responses)
Lead Contact (27 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (72 Responses)
Question 1 (58 Responses)
Question 1 Comments (67 Responses)
Question 2 (60 Responses)
Question 2 Comments (67 Responses)
Question 3 (0 Responses)
Question 3 Comments (67 Responses)
Question 4 (54 Responses)
Question 4 Comments (67 Responses)
Question 4 (0 Responses)
Question 5 Comments (67 Responses)

Group
Western Small Entity Comment Group
Steve Alexanderson
Yes
According to the SAR, “All devices and equipment attached to the electric grid must be modeled to accurately capture how that equipment performs under static and dynamic conditions.” The comment group finds this statement to be absolute and overly inclusive. We don’t believe that every 25 W lamp can or should be modeled. We suggest that there should be a qualifying statement limiting this Project to BES Facilities and Elements, or something with these limits.
Yes
1)Attachment 1 Item 1 under the steady-state header asks for the Aggregate Demand at each Load Serving Entity bus as a minimum. Since “bus” is not a NERC defined term, we looked at the IEEE dictionary and found the most appropriate definition is “A conductor, or group of conductors, that serves as a common connection for two or more circuits.” By this definition, we see that Load Serving Entities will be asked to report demand data for many hundreds of thousands of buses, the vast majority of them at service-level voltages. Per R1.1, the PC will not have the authority to reduce this minimum number of buses to a more reasonable number. We can’t imagine the SDT is considering this degree of modeling, and suggest that some bounds be put around the “each bus” requirement. We suggest: “2. Aggregate Demand at each Bulk Electric System bus [LSE].” Another solution would be to add an applicable facility section as other recent standard projects are doing. 2)The comment group is unsure what is meant by Item 5 under the dynamic header of Attachment 1. The requirement does not specify whether the Demand data sought is entity wide, by bus, by metering point, etc…
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Agree
Central Lincoln
Group
Northeast Power Coordinating council

Guy Zito
Yes
The SAR should not be posted with the Standard. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard's development or revision. Posting the Standard for comments and ballot means that the SAR is "water under the bridge", and that industry's input on the SAR doesn't mean anything. We support combining Standards MOD-010 through MOD-015 into fewer standards. Suggest revising SAR Information Section Item 3a. to: Identify responsibility to provide and who receives the data.
Yes
The format of part 1.2 should be is accepted to be used in the industry (i.e. what is already in use). The R1.6 stipluated 13 month schedule is odd. Explain the rationale or change to 12 or 15 months. R2 must consider communication when any change occurs. Suggest revising to: …within 30 days of developing any changes or following a written request… Part 4.2 refers to dynamics data. It should be part of R1 and Attachment 1. Part 1.5 is unclear and it's purpose is unknown. The use of the term "case type" is confusing as these are already specified as steady state, short circuit, and dynamics. Part 1.5 also states that the scenarios to be modeled should be included. These models should be able to be used for numerous different testing scenarios in the future, and there is no need to specify those scenarios as part of data collection. A part 1.7 should be included that would read: 1.7 No "Black Box" models shall be permitted without a complete description including operational description of inputs to the model. In Requirement part 1.1 remove the term "at a minimum" and change the part to read "Specification of the required data per information listed in Attachment 1;" In Attachment 1 add to Item 9 in the table the following statement "Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. (BA, GO, LSE, TO, TSP)" to the Dynamics and the Short Circuit columns. TPL-001-4 refers to MOD-010 and MOD-012. This will need to be modified or preferably cross reference to other standards should be eliminated to avoid this problem. Regarding R2, this requirement is unclear on the requesting part. Requirement R1 assigns the Planning Coordinator (in conjunction with its Transmission Planner) the responsibility to develop steady-state, dynamics, and short circuit modeling data requirements "within 30 calendar days of a written request for the data requirements and reporting procedures". The PC is the entity having a need and therefore will make a request for submission of data by the entities listed in R2 (BA, GO, LSE, RP, TO and TSP) in accordance with the procedures for data reporting. It is unclear as to who issues "a written request" for the data requirements and reporting procedures. Is it the entities listed in R2 themselves, or other entities not listed, or the PC itself? R2 is unclear on what request it is, and who makes the request. Measure M2 seems to suggest that it is the PC who receives such a request. That being the case, the question becomes who issues the request, and the reason for the request. Regarding R3, the sentence "For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient." should be deleted since it is not a requirement. It is a measure of compliance, which is already adequately captured in Measure M3. Regarding R4, the phrase "including the technical basis or reason for the technical concerns," implies that the PC is required to provide this in the written notification, but there is no such requirement stipulated anywhere. If this is not a requirement, then it does not add any value to Requirement R4 as this requirement stipulates the tasks required of the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider upon receiving a notification from the PC/TP. Part 4.2 is out of place and should be removed. As presented, part 4.1 projects a separate requirement for dynamics data describing the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables which should have been (and most appropriately) included in R1 and Attachment 1. To address the intent of part 4.2 thus allowing for the situation that a PC or TP may request additional data in its notification, we suggest the following wording change to R4. The change reflects conformance to NERC Standard requirement format, and it should be made into two Requirements: Each Planning Coordinator or Transmission Planner shall deliver written notification of technical concerns with the data submitted under Requirement R3 or convey the need for additional data. Each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: 4.1 The proposed 4.1 4.2 The proposed 4.3, assuming 4.2 will be

removed as suggested Regarding the VSL for R2, the condition before the “or” may render a Responsible Entity being assigned a Severe VSL if it fails to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days but short of exceeding the 75 days. Suggest this VSL be revised to: The Planning Coordinator did not provide its data requirements and reporting procedures according to Requirement R2, OR The Planning Coordinator provided its data requirements and reporting procedures according to Requirement R2 greater than 75 calendar days after a written request.
No
Requirement R1 should not make reference to a non-existent standard. Part 1.2 can be condensed to: 1.2 Validate its portion of the system in the dynamic models through simulation of dynamic local events. If within any period of 24 months more than one event may have occurs, only one validation is required for the 24 month period. In part 1.2, add a description or definition of the term “Dynamic Local Events”. Regarding R1, “must” with “shall” to be consistent with other standards. Regarding the VSL for R1, the second condition under Low VSL needs to be qualified so that the situation only applies when the time between the previous dynamic local event and the events that occurred that required a simulation within 12 months exceeded 24 calendar months. Regarding the VSLs for R2, all instances of “planning coordinator” should be capitalized. An acceptable validation generally comprises comparing data available in EMS with simulation predictions produced by planning models. Our past experience is validation is less challenging for steady-state comparison, but quite a challenge in validating dynamic performance due to EMS or off-line models do not sufficiently represent all impactful activities of power plants or devices, and equipment owners are not supportive to ensure models are current and adequate. As written, the Standard is applicable strictly to Planning Coordinators. Equipment owners are not partners of validation. Unless the language of the Standard places sufficient responsibility on equipment owners to check models for their own equipment frequently, and share accurate current operating information, the success will be limited. We suggest the Drafting Team expand this Standard to address this concern or otherwise to enable Planning Coordinators to meet their obligations stipulated in the Standard. If the EMS data and planning model responses are significantly different, either models may contain misrepresentations or bad data, or some actual activities are not modeled. The Standard should stipulate accountability on equipment owners to report or assist identifying changes to operating settings (which are unavailable in EMS) that affect models or operating practices not modeled. Failed validation should include a greater degree of accountability to equipment owners.
Individual
Thomas Foltz
American Electric Power
No
Yes
AEP recommends that team provide clarification with respect to the functional entities listed within the table for Attachment 1. For example, in state-state item number 2, it lists the LSE as the functional entity. Does this depect the likely source to provide the information or is this the only entity that will be asked and be required to provide this information? AEP prefers flexibility within this approach as RTO practices might vary in how they collect this information.
Yes
Individual
John Gross
Avista
No

Yes
1. Requiremt R5.2 is unclear with the term "data modifications." Removing R5.2 and consolidating R5.1 into R5 would still meet the objective of requiring the PC to sumbit data to the ERO. 2. Historically the industry has seperated transmission system modeling data into categories such as what was done in Attachment 1: steady-state, dynamics, and short circuit. The drafting team can consider consolidating the three columns therefore stating all necessary modeling data for a specific item in a single location. Example: AC Transmission Line or Circuit requires i. impedance (all sequences and mutuals), ii. ratings, iii. status. 3. The drafting teams should provide guidance on how the PC should handle Generating Units with capacity limits below the NERC functional entity registration limits. Generators below the 20 MVA single unit and 75 MVA plant are still desired to be modeled both in the interconnection wide model and PC level models. 4. The assignment of functional entities in Attachment 1 may not be sufficient. A bus, for example, may be owned by a GO therefore designating only TO as being responsible could leave a gap. The drafting team can consider the approach used by the WECC-0074 drafting team in developing MOD-11 and 13-WECC-CRT-1. Stating each TO of transmission facilities represented and each GO of generation facility represented. 5. The item Each Bus in Attachement 1 should include requirements for lat, long location and substation. 6. The drafting team should provide an acceptable threshold of station service auxiliary load required to be modeled as stated under Generating Units of Attachment 1. WECC has established a threshold of 1 MW or greater to be explicity modeled. 7. Attachment 1 should include the item "Substation" requiring lat, long location and grounding impedance. Providing this additional data will aid in addressing the geomagnetic induced currents study requirements. 8. The drafting team should consider aligning data requirements in MOD-025-2 with the generator real and reactive power capabilities required in Attachment 1.
Yes
Requirement R1 should be split into two seperate requirements stating (1) the requirement to have a documented process and (2) a requirement to implement the process.
Individual
Lynn Schmidt
NIPSCO
No
Yes
For MOD-032, Data for Power System Modeling and Analysis, there are two primary reasons to vote no: The first is that under MOD-032, the responsibility for coordinating model building passes from the RRO/RFC, to the planning coordinator, MISO. For NIPSCO, developing accurate and usable models requires close coordination with the two large neighboring interconnected utilities having the greatest impact on NIPSCO, Commonwealth Edison and AEP. NIPSCO, CE, and AEP are all in the same regional reliability organization, RFC. Having RFC as our model building coordinator has greatly facilitated our model building efforts. Both in terms of quality and quantity, the present arrangement has resulted in a smooth and coherent exchange of data and coordination in the development of models. Under MOD-032, this high level of coordination and cooperation that exits today will be lost to the detriment of NIPSCO. NIPSCO's model building will be coordinated through MISO, while the model building efforts of CE and AEP will be coordinated through PJM. This separation into two different coordinators can only hinder model building and eventually lead to poorer models. If NIPSCO were in the middle of MISO instead of on the boundary with PJM this might not be a concern, but we're on the boundary with PJM. Also, MISO has sometimes struggled in their model building efforts. In the 2000's, MISO promoted their Model-On-Demand (MOD) software, which would create future powerflow models by "pushbutton" and which companies would use to submit their NERC MMWG modeling requirements. While Model-On-Demand still survives, neither of these two goals has been achieved and there have been no discernible improvements. RFC has a much more sustained and proven track record of

proficient model building coordination. If one of the rationales for MOD-032 is to produce better system models, the results will be the exact opposite. The second is that under MOD-032, generation owners will submit their data directly to the planning coordinator, MISO, instead of submitting the data to the transmission planner, NIPSCO. Presently, when the generator owners submit their data directly to NIPSCO, it gives us the opportunity to review their data for accuracy and consistency prior to inclusion in any model. NIPSCO and other transmission planners/owners have an incentive to review generator owner data as they will experience the greatest impact of incorrect modeling. MISO will not be able to achieve this level of review of generator owner data, nor will they have any incentive to do so.
Yes
While model validation is a laudable goal, the proposed approach is way over the top. Checking data every two years is a totally unnecessary and unproductive expenditure of resources. Having been involved in prior data validation efforts, including RFC's System Snapshot in 2005, once every ten years is a much more realistic and productive approach. Model validation every two years is like checking your temperature every two minutes. Some may believe that model validation every two years leads to models that are perfect with 100% accuracy 100% of the time, but this is an unrealistic and unattainable goal.
Individual
Kathleen Goodman
ISO New England, Inc.
No
Yes
Under R1 - Requirement R1.5 is unclear and it’s purpose is unknown. The use of the term “case type” is confusing as these are already specified as steady state, short circuit, and dynamics. R1.5 also states that the scenarios to be modeled should be included. These models should be able to be used for numerous different testing scenarios in the future, and there is no need to specify those scenarios as part of data collection. A requirement 1.7 should be included: 1.7 No “Black Box” models shall be permitted without a complete description including operational description of inputs to the model.
Yes
Individual
Martyn Turner
LCRA Transmission Services Corporation
No
Yes
To address existing entity NERC registration in the ERCOT region, “Planning Coordinator” should be replaced with “Planning Authority and /or Reliability Coordinator”. This is shown below for the introductory paragraph (R1) but would apply to the other requirements and sub-requirements as well. Also, the requirements for the Transmission Planner are not clearly specified and LCRA TSC recommends that this requirement only apply to the PA and /or RC. R1. Each Planning Authority and /or Reliability Coordinator shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area, including: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] In Attachment A, a footnote should be added to the short circuit section of the table: * Positive sequence data may be substituted for negative sequence data where appropriate.

Yes
To address existing entity NERC registration in the ERCOT region, LCRA TSC recommends replacing “Planning Coordinator” with “Planning Authority and /or Reliability Coordinator”. This is shown below for the introductory paragraph (R1) but would apply to the other requirements and sub-requirements as well. Short circuit modeling data was clearly specified in the proposed MOD-032-1; however, the requirement to validate short circuit modeling data is not considered in the proposed MOD-033-1. For consistency and completeness, LCRA TSC recommends adding a requirement to validate short circuit data and modeling similar to the requirements proposed for steady state and dynamics. LCRA TSC believes requirement R1.3 is redundant as it is already covered in requirements of the proposed MOD-032-1. LCRA TSC recommends deleting requirements R1.3. In R2, LCRA TSC believes the Transmission Owner, as the asset owner, should be responsible for providing actual system behavior data. The reporting of data and modeling validation efforts is not presently part of the requirements in MOD-033-1. LCRA TSC recommends adding a requirement for the Planning Authority and /or Reliability Coordinator to report on validation results. R1. Each Planning Authority and /or Reliability Coordinator must implement a documented process to validate the data used for steady state, short circuit, and dynamic analyses (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses that includes, at a minimum, the following items: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.3. Validate its portion of the system in the short circuit model by comparing it to actual system behavior to check for discrepancies that the Planning Authority and/or Planning Coordinator determines are large or unexplained at least once every 24 calendar months through simulation. R2. Each Reliability Coordinator and Transmission Owner shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator that the Planning Coordinator requests to perform validation under Requirement 1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3. Each Planning Authority and/or Planning Coordinator must provide a final report summarizing the data validation process, findings, and conclusions.
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
Yes
Clarification is requested on whether TOs would still be responsible for submitting the steady state and dynamic data for GOs since MOD-032 R3 states that “Each BA, GO, LSE, RP, TO, and TSP shall provide steady-state, dynamics, and short circuit modeling data to its TP) and PC according to the data requirements ….” The current process requires the TOs to submit the data on behalf of the GO, which is not practical since the TOs don’t own the GO data. If the process of TOs collecting the GO data and formatting the data remains the same, it is requested that a statement be added to the standard to the effect that the TO will not be violation of the requirement if the GO does not provide the data to the TO or if the GO does not provide the data in the required format and the TO makes a mistake in providing the data in the required format.
Group
Arizona Public Service Company
Janet Smith
No

Yes
Yes
Individual
Jonathan Appelbaum
The United Illuminating Company
R1 contains the phrase in conjunction with the Transmisison Planners. We are concerned that this could be interpreted to place an enforceable responsibility on Transmision Planners to participate or seek out to participate. The phrasing does not oblige the PC to listen to the TPL so there is no reason to include the phrase.
1) We are concerned with the word accurate in the purpose statement. Reliaility Standards are read as whole. At times the best data available may not be accurate by definition. 2) We are concerned with what model is being validated against an actual disturbance. There are many models, steady-state, dynamic, short circuit, planning horizon with various scenatios, 7 day operating model, and real-time hourly.
Individual
Eric Bakie
Idaho Power Company
Yes
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power System Planning comments that system models are the foundation for assessing system reliability and operating the system securely. System models are used to establish Path SOLs, IROLs, mitigation plans, generation interconnection studies and their impact on system performance, etc. Why was such an important standards such as the revised MOD Standards selected for informal development on accelerated schedule? Idaho Power System Planning comments that due to the importance of a MOD standards and the potential impact of not following such standards on system reliability that NERC BOT adoption of the new MOD standards by the end of the year seems like an unreasonable timeline. FERC did not approve several MOD standards in Order 693, due to their "fill-in-the-blank nature" and requirement assignment to the RRO, which is not in the NERC Functional Model; Idaho Power System Planning comments that due to the importance of the impact of MOD standards on reliability objectives, development of the replacement MOD Standards should not be rushed.
Yes
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power does not agree with the approach in MOD-032-1. Since FERC has already refused to approve "fill-in-the-blank" standards where the RRO was responsible for "fillling-in-the-blanks", why does the SDT think FERC will approve more "fill-in-the-blank" standards where each any every Planning Coordinator is "filling-in-the-blanks"? Obligations must be reasonably prescribed within the standard, and not simply "refer" to requirements and obligations to be determined by some other entity. The "fill-in-the-blank" approach is not a reasonable delegation of authority.
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. MOD-032-1 Requirement R1 requires each Planning Coordinator to develop data reporting requirements and procedures for its planning area that includes the attribuites listed in Parts 1.1-1.6. This approach significantly differs from the current processes used by WECC members for interconnection model development, data reporting, and basecase data compliation in that WECC

members are expected to follow the established WECC Regional data reporting procedures and data reporting requirements. In addition, R1-Part 1.5 and 1.6 allows each PC to specify the case types and scenarios and schedule for submission or confirmation of data without a formal review and approval process of interconnection stakeholders or without considering the Reliability Assurer's programmatic needs which are beyond those of the individual Planning Coordinator are; which is also significantly different from the WECC basecase model development process where the WECC SRWG develops the case types and scenarios to be modeled which are then reviewed and approved by WECC TSS prior to basecase creation via a formal review process. WECC and WECC Members have also significantly invested into new software tools known as the Base Case Coordination System that already define the data reporting format data. Submitters will be expected to follow the data reporting format requirements established within the WECC BCCS. WECC committes such as the WECC Planning Coordination Committee, the WECC Technical Studies Subcommittee, the WECC System Review Group and the WECC Model and Validation Working Group have invested considerable time and effort in defining WECC data reporting requirements and processes through the development (and maintenance) of the WECC Data Preparation Manual, the WECC Generator Testing and Model Validation Policy, the MOD-11 and 13-WECC-CRT-1 approved Regional Criteria, and numerous other WECC policies and guidelines. It seems that little reliabilty benefit is gained by requiring each PC to develop data reporting requirements and procedures for its planning area when well established and successful processes, policies, procedures, and data reporting requirements already exist within the WECC Region. It is understood that NERC MOD-011, MOD-013, MOD-014, and MOD-015 list the RRO as the applicable entity and as idenfied in the SAR references to the RRO should be removed for exisitng and new MOD requirements. Idaho Power System Planing agrees that the RRO is not in the NERC funcitonal model and should not be referenced in MOD-032 and MOD-033 requirements. However, the Reliability Assurer (RA) is included in the NERC Functional Model and provides a mechanism to link the well established and successful data reporting procedures and requirements developed and managed within the WECC Region to the expectations listed in MOD-032 Requirement R1 for each NERC Planning Coordinator. Inclusion of the Reliability Assurer as an applicable functional entity and establishment of an additional Requirement or attribuite of Requirement R1 (i.e. Part 1.7) in MOD-032-1 improves the quality and enforceability of the standard if such a requirement also required a PC to establish its modeling data requirements and reporting procedures consistent with the data reporting requirements and procedures of its Reliability Assurer, where an established process exists. For example, under NERC MOD-032 R1 a PC could establish a data reporting procedure that includes all items listed in Requirement R1-Parts 1.1-1.6 but does not include data reporting requirements for UFLS or UVLS dynamics data for inclusion in the interconnection study cases. A TO reporting entity could then report all the data as required under Requirement R3 in accordance with its PC's R1 procedures. In this example, both the PC and TO would be in compliance with NERC MOD-032 requirements but would not meet WECC established data reporting requirements since dynamics data in addition to the items required in NERC MOD-032 Attachment 1 such as UVLS and UFLS data records are required data types per WECC data reporting requirements. This example could be further extended to inclusion of line and transformer relay modeling data in WECC basecases, which are data types WECC is taking steps to require data submitters to include in their data submittals. NERC MOD-032 as drafted does not provide a mechanism to collect such data if a PC chooses to deviate in its R1 procedure from the WECC established regional data reporting requirements captured in existing processes. Adding a requirement in NERC MOD-032 that includes the Reliability Assurer and also requires a PC to establish its R1 model data requirements and reporting procedures consistent with established RA data requirements and reporting procedures strengthens the enforcabilty of the standard and ensures each PC, BA, GO, LSE, RP, TO, TP, TSP is reporting the required modeling data consistent with well establised WECC Regional Requirements. Idaho Power System Planning comments that page 22 of NERC MOD-032 specifically states "The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support what is already in place..." Not one of the MOD-032 requirements reference retaining consistency with regionally established processes and procedures, thus MOD-032 does not create a framework to support what is already in place. Inclusion of the RA Functional Entity in the MOD-032 Standard and establishing requirements for a PC to develop its procedures as required by R1 consistent with existing processes and procedures established and maintained by the RA better demonstrates the ideas discussed in the Guidelines and Technical Basis language on page 22. The approach of including the RA in MOD-032 creates a framework to support what is already in place. Ballot Position: Negative with the following comments:

MOD-032-1 would be acceptable to Idaho Power System Planning if the standard were modified to include the Reliability Assurer NERC Functional Entity and add an additional requirement or modify Requirement R1 to require each Planning Coordinator to establish its planning area modeling data and reporting requirements consistent with the modeling data and data reporting requirements of its RA if such requirements are established within its interconnection region (especially for the WECC Regional Entities). Standards should be drafted with clear goals in mind and a way to make those goals achieveable and measureable. This standard does neither, as it tell the Planning Coordinator to develop it's own requirements and procedures. Standards are to help the industry standardize and make the system more reliable. This is the wrong approach.
Yes
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power System Planning agrees with the approach in MOD-033-1.
Idaho Power submitted an incorrect vote for this project. Idaho Power intended to vote negative on this project. Idaho Power System Planning agrees with the approach in MOD-033-1. While Requirement R1 Item 1.3 addresses FERC Order 890, paragraph 290 and FERC Order 693, paragraphs 1211 and 1220 directives, in that system models should be modified and updated to improve their accuracy when validation assessments identify unacceptable model accuracy concerns; R1 Part 1.3 does not provide a timing requirement that holds a Planning Coordinator accountable for correcting the model accuracy when a discrepency it identified. Idaho Power System Planning comments that R1-Part 1.3 should be modified to include a time requirement for correcting the model deficiency within six calendar months of determining such discrepency. MOD-032-1 Requirement R4 provides a mechanism for a PC to collect corrected data from data owner(s) in a timely manner; similarly MOD-033-1 Requirement R1-Part 1.3 should establish a time requirement for Planning Coordinators to implement model corrections. Ballot Position: Negative with the following comments: MOD-033-1 would be acceptable to Idaho Power System Planning if Requirement R1-Part 1.3 was modified to include a time requirement that holds Planning Coordinators accountable for implementing model corrections. A six month timeframe seems reasonable for such a requirement.
Group
Luminant
Rick Terrill
No
Yes
Luminant appreciates the work of the Ad Hoc team and generally agrees that the data modeling requirements are appropriate. Luminant is voting negative due to a moderate concern: The Planning Coordinator develops the details data specifications and reporting requirements, including the timelines for reporting. Modeling methods change over time, as could data needs. In MOD-032, R3 or R4, the SDT should address the issue of data requests where the requested data may not be readily available. This could be easily addressed by a technical basis documentation similar to that noted in R4.
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Group
BC Hydro and Power Authority
Patricia Robertson

No
BC Hydro supports the consolidation of the MOD standards. However BC Hydro has voted Negative as BC Hydro has concerns with assigning the responsibility of the modelling development framework and validation to the Planning Coordinator (PC). Currently, the RRO (WECC for our region) is developing data requirements and reporting procedures to have consistency (technical details to form adequate base cases) across the region. If the standard assigned the modelling data requirements and reporting procedures to the RRO instead of the PC , then coordination for the ERO (NERC) interconnection models would occur among 8 RRO's as opposed to 80 PCs (currently 80 entities are registered as PCs according to NERC's site. WECC is also currently developing guidance for model validations (including frequency) for its region and BC Hydro believes this is the appropriate level (ie at the RRO level) to ensure consistency. In summary, the RRO's have the resources, including drafting committees, working groups and task forces to develop the modelling data requirements, reporting procedures and model validation to create adequate and consistent interconnection models for the ERO.
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Individual

David Wang
SDG&E
No
San Diego Gas & Electric (SDG&E) recommends a negative vote on NERC Project 2010-03: Modeling Data (MOD B), which proposes Reliability Standards MOD-032-1 and MOD-033-1, for the following reasons. First, while MOD-032-1 consolidates the concepts from the original data requirements of MOD-011-0 and MOD-013-0, it also includes a new requirement to account for the collection of short-circuit data. SDG&E does not believe that it is necessary for the Planning Coordinator to receive short-circuit data to effectively model the interconnected transmission system because short-circuit data is really only useful at the local level, and in most cases does not relate to system-wide interconnections. Secondly, the results of analyzing this data are already available in two places - as part of the annual FERC Form 715 filing, which provides a summary of all Transmission Planning activity for the prior calendar year as well as in the annual Grid Assessment Study Report. Finally, unlike steady-state and dynamics data, short circuit data is only accessible through use of the ASPEN program, which would have to be purchased and is quite costly. Should the short-circuit data collection requirement unfortunately remain in the Standard, its submission should only be required, at a maximum, once every 13 calendar months per sub-requirement R1.6. SDG&E also takes issue with MOD-033-1, which requires the Planning Coordinator to validate data for steady state and dynamics models within its area through simulation of a dynamic local event. SDG&E does not believe this requirement is necessary, given that load flow data is updated constantly, and any new data, including changes to the system, is incorporated into subsequent case submissions. Lastly, case validation has taken place previously due to special case requests from WECC, which required a case to be made from data at a given point in time. To SDG&E’s knowledge, there were no major discrepancies between the requested point-in-time case and actual data values that were used to validate the requested case. As such, data validation cases have been requested in the past and no significant issues have appeared.
San Diego Gas & Electric (SDG&E) recommends a negative vote on NERC Project 2010-03: Modeling Data (MOD B), which proposes Reliability Standards MOD-032-1 and MOD-033-1, for the following reasons. First, while MOD-032-1 consolidates the concepts from the original data requirements of MOD-011-0 and MOD-013-0, it also includes a new requirement to account for the collection of short-circuit data. SDG&E does not believe that it is necessary for the Planning Coordinator to receive short-circuit data to effectively model the interconnected transmission system because short-circuit data is really only useful at the local level, and in most cases does not relate to system-wide interconnections. Secondly, the results of analyzing this data are already available in two places - as part of the annual FERC Form 715 filing, which provides a summary of all Transmission Planning activity for the prior calendar year as well as in the annual Grid Assessment Study Report. Finally, unlike steady-state and dynamics data, short circuit data is only accessible through use of the ASPEN program, which would have to be purchased and is quite costly. Should the short-circuit data collection requirement unfortunately remain in the Standard, its submission should only be required, at a maximum, once every 13 calendar months per sub-requirement R1.6. SDG&E also takes issue with MOD-033-1, which requires the Planning Coordinator to validate data for steady state and dynamics models within its area through simulation of a dynamic local event. SDG&E does not believe this requirement is necessary, given that load flow data is updated constantly, and any new data, including changes to the system, is incorporated into subsequent case submissions. Lastly, case validation has taken place previously due to special case requests from WECC, which required a case to be made from data at a given point in time. To SDG&E’s knowledge, there were no major discrepancies between the requested point-in-time case and actual data values that were used to validate the requested case. As such, data validation cases have been requested in the past and no significant issues have appeared.
Individual
John Bee
Exelon and its' Affiliates

Yes
The steady-state and dynamic data previously covered by MOD-010 through MOD-013 can be considered system-wide data, while short-circuit modeling is more of a local issue. The inclusion of the short-circuit data in the new standard unnecessarily complicates the process. While the move toward reducing the number of standards is positive development, going too far can complicate data collection and compliance unnecessarily. The short-circuit data requirements should be a separate standard.
Yes
In requirement R1 of MOD-031, the RRO is to work with the TOs, TPs, GOs, and RPs to develop requirements and reporting procedures. In R1 of MOD-032-1, this language has been modified to only specify the transmission planners. Is this change intentional? Many large transmission owners are no longer transmission planners in the eyes of NERC. Transmission Owners who are not also Transmission Planners have driven many of the improvements in the MOD-010 and MOD-012 reporting processes. It appears from R1 that the TOs would no longer be responsible for collecting generator data from the GOs unless this is made an assigned task by the TP. Is this interpretation correct? The requirement for short-circuit data will involve combining data from software such as PSS/E, CAPE, and ASPEN. Data interchange between applications is not always well supported and may involve the loss of some data. Does NERC plan to work with the software vendors to simplify this process, or is the process more likely to be settling on a least common denominator? Requirment R4.3 suggest that 4.3 below should be at least 60 days not 30 days. Typically we may have to go back to a vendor for this information and 30 days may be problematic in getting the information.
Yes
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Frank Gaffney, Florida Municipal Power Agency
Individual
John Seelke
Public Service Enterprise Group
Yes
a. Specific FERC directives that are being addressed by this project are not identified. MOD-032-1 and MOD-033-1 (p.1 of each) merely state “Several directives remain outstanding (including from FERC Order No. 693) that relate to MOD-010 through MOD-015.” The individual directives should be clearly identified in the SAR. b. The SAR should address how data for planned facilities (as opposed to existing facilities) is intended to be provided. (MOD-032-1 – Attachments 1 addresses this superficially.) Entities that are planning new facilities are subject to reliability assessments under FAC-002-1. Assessments are conducted by the “Transmission Planner and Planning Authority” in accordance with R1 of FAC-002-1, and they would have the data for new facilities. However, including that data into planning models has several issues that the SAR does not address. One issue is data confidentiality, which is discussed in item 1.c below and which applies to data for existing facilities. The second issue is determining the planned facilities for which data should be requested. Many generation and transmission projects will be competitive projects, and all of them will not be needed. The entities developing those projects would need to provide their permission to allow the data that they have provided to the PC or TP under FAC-002-1 to be used for MOD-032-1, provided that the data to be used for modeling is limited to that which they have provided under FAC-002-1 and no more. Eventually, model builders may select future projects for their models. c. Data confidentiality is a major issue which the SAR has not addressed adequately. Data may be confidential for a number or reasons, but the two greatest are (1) it is CEII and (2) it is commercially sensitive. The issue is briefly

discussed in the SAR on p. 8 in setion 3.e “Sharability (an issue tangential to the MOD standards).” The SAR should require the the drafting team develop solutions to the problems identified in SAR section 3e. Specifically, it should require that the team address (1) what entities will have access to which confidential data and (b) what provision will be required for such access to ensure that confidentiality is maintained. That should be a requirement in the SAR. The two comments below are related to “data confidentiality.” i. Data may be needed by other that a PC of a TP. TOs and GOs may need short circuit data for protection system coordination. TOPs may need existing data to validate their databases. ii. In MOD-032-1, R1 subpart1.3 does not address shareability adequately. First, it leaves the parameters of “shareability” up to each PC’s procedure, a non-starter if the data is to be shareable on an Interconnection-wide basis. We will provide further comments on R1 in response to the question #3 on MOD-032-1.
No
We recommend that the team explain why it did not elect pursue a Section 1600 data request as opposed to a standard. A Section 1600 data equest would require that specific data be requested in a particular format. It would require that data confidentiality be addressed. It would allow for additional data to be added or deleted in a process that is considerably shorted than changing a standard.
a. The standard has failed to address the concerns identified in the existing SAR regarding standard format in section 3.c on p. 7 and data confidentiality (i.e., sharing) from section 3.e on p. 8. i. R1 allows each PC to specify (1) the data it will request, and (2) the data format, including the level of detail, and (3) that shareability is required without addressing how data confidentiality will be addressed. R1 needs common NERC-wide solutions, not PC-specified solutions. i. In addition, we do not see understand why subpart 1.5 (case types and scenarios to be modeled) is contained in a data request that data providing entities must submit in R3. The data requested should be sufficient to address whatever the model builders need. In other words, how is this a concern of the data providers? ii. We object to subpart 1.1 that allows each PC or TP to specify data “that includes, at a minimum, the data listed in Attachment 1.” Attachment 1 imposes data reporting obligations on numerous entites other that a PC or TP - see section 4.1 of MOD-031-1. Therefore, the phrase “at a minimum” sets no limit on what can be requested and subequently provided by data owners for compliance with MOD-031-1. This language is a “fill-in-the-blank” requirement and therefore unacceptible. b. Regarding Attachment 1: i. We do not understand what “share of reactive contribution for voltage regulation” which is designated for items 3, 7, and 8 means. ii. Item #9 is objectionable for the reasons described the our response in 3.a.ii above. iii. Other standards require generator data to be provided to the PC or TP such as the four standards in Project 2007-09 Generator Verification (PRC-019-1 – Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection, PRC-024-1 – Generator Performance During Frequency and Voltage Excursions, MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions, and MOD-027 -1 – Verification of Generator Unit Frequency Response. If a PC asks for the same data in MOD-032-1 as is required by these standards, a Registered Entity could face double compliance jeopardy, which is unacceptable. c. Regarding R3, two entities are designated to receive data (the PC and the TP). This will create a burden and a compliance issue. The PC should be designated to receive the and entity’s data. d. Regarding R4, two enity’s (the PC or the TP) may request clatification on the data submitted. This again should be restricted to one entity as designated by the PC. Otherwise, a data providers may receive multiple requests. In addition, the 30 days in R4 should be changed to 60 days. Even though the language allows the PC or TP to extend the time, there is no assurance that such an extension will be granted.
No
The prior comments to Q#2 regarding a Section 1600 data request instead of a standard apprly to MOD-033-1 also. But with resepct to the specific approach taken in MOD-033-1, we have these comments: R1 requires each PC to validate performance for “its planning area.” Throughout NERC, ERCOT is the only entity that is a PC as well as an Interconnection. The Eastern Interconnection has 54 PCs and in WECC has 29 PCs. A PC’s modeled performance versus its actual performance for “its planning area” is dependent upon data within the Interconnection. That data includes data for entities submitted to OTHER PCs. A PC’s modeled performance is also dependent on the correct modeling by other PCs. In other words, within an Interonnection with multiple PCs, the data and modeling decisions of each PC within an Interconnection impacts all PCs validation ability within that Interconnection.
a. There should be a requirement for each PC to coordinate with the other PCs within its

Interconnection in R1. b. To prevent data errors, data should be validated in MOD-032-1 by the data owner prior to submission and checked by the PC after it is submitted. There is no requirement in MOD-032-1 for the PC to confirm that the data submitted by a data owner is reasonable. R4 in MOD-032-1 should require that the PC perform data validation, and as a result of such data validation efforts, it may request data clarification under R4.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We question the need to ask this question when the consolidated standard is already posted for commenting and balloting. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard development/revision project. Posting the standard for balloting at the same time suggests that there is already a foregone conclusion on the need and the scope for this project , and that the industry's input on SAR would seem irrelevant. The IESO understands that posting a SAR and the draft standards for comment at the same time can improve standard development efficiency, and we support it to the extent that sufficient technical information has been obtained to facilitate the development of a draft standard at the informal outreach stage. However, we are very concerned about the fact that the industry was asked to ballot the draft standard when the need and scope of the draft standard have not been commented on and supported by the industry, and the standard itself has not been drafted by a formal standard drafting team. Such an approach appears to: a. Deviates from the normal standards development process as presented in the Standards Process Manual (SPM); b. Contradicts and perhaps violates the intent of the established standard development process and ANSI principles to have new and revised standard formally developed through an open and inclusive process before being presented to the RBB for balloting. The industry is being asked to ballot a set of standards that has not been formally developed. This concept appears to be fundamentally flawed. We propose that the SDT convey our concern to the NERC senior management and the Standards Committee. We further suggest that NERC and the SC evaluate alternative approaches or make revisions to the SPM to provide the needed flexibility that can further improve the efficiency in standard development if certain elements in the existing SPM are assessed to restrict such improvements.
Yes
a. R2: This requirement has an ambiguity regarding the exchange of information, specifically: who makes a request, and who receives the results. We recommend that the following phrasing resolves this issue: R2. When a Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider within a Planning Coordinator's planning area requests the data requirements and reporting procedures, the Planning Coordinator shall provide to the requesting party the data requirements and reporting procedures within 30 days. b. R3: The sentence "For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient." is not needed since it is not a requirement. It is a measure of compliance, which is already adequately captured in Measure M3. c. R4: This requirement generates the following concerns: • A need to strengthen the stipulation for the PC to provide a technical reason • While 4.2 may account for the acquisition of user models, R4 overall reads as an undue emphasis on dynamic data that does not allow for the acquisition of steady-state (or other) data not previously defined under R1. This should be more generic to accommodate evolving modeling requirements. R4.2 should then be clarified to specifically account for non-standard models not supported by vendor software, placing responsibility on owners who are more easily made accountable to the PC, rather than on vendors who are not. As such we propose that R4 be worded as follows: R4. Upon delivery of written notification from its Planning Coordinator or Transmission Planner regarding a request for data, whether resulting from a technical concern with data submitted under Requirement 3 or a revision to the data requirement defined under Requirement R1, and whose notification shall include the technical basis or reason for the request, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: 4.1 Provide either the requested data or an explanation with a technical basis for not providing the requested data; 4.2

If requested by the notifying Planning Coordinator or Transmission Planner, provide additional data describing the characteristics of the model that would enable accurate representation otherwise not provided by standard software, including: block diagrams, values and names for all model parameters, and a list of all state variables; and 4.3 Provide the response with 30 calendar days, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.
Yes
a. R1: Suggest to replace “must” with “shall” to be consistent with other standards. b. VSL for R1: The second condition under Low VSL needs to be qualified that the situation only applies when the time between the previous dynamic local event and the events occurred that required a simulation within 12 months exceeded 24 calendar months. c. VSLs for R2: all “planning coordinator” should be capitalized. d. R2: This requirement generates the following concerns: • The Realability Coordinator or Transmission Planner may not be aware of equipment operational settings, facility impactful activities, etc., which may affect validation. Furthermore this data, as “real time” settings, may not have been made available under MOD 32 – R3,R4. As such responsibility must be expanded to equipment owners to provide “actual system behaviour data”. Without expanded accountability, RC and TP may not be able to acquire this data on the PCs behalf. As such we propose that R2 be worded as follows: R2. Each Reliability Coordinator, Transmission Operator, Generator Owner, Load Serving Entity and Transmission Owner shall provide actual system behaviour data (or a written response that it does not have the requested data) to any Planning Coordinator that the Planning Coordinator requests to perform validation under Requirement 1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation. e. R2: This requirement generates the additional concern that entities are only required to provide data upon request, in particular operational settings. It may take some time for the PC to identify the cause of discrepancies during validation, and may ask for the wrong information (modeling vs. setting), for example receiving a governor model may not include the detail that it has been turned off. Consequently it is recommend that either MOD-032 or MOD-033 contains containing some language that requires each RC, TO, GO, LSE and TO (described above) to “self report” to the PC any changes in operational settings or other impactful actions within a certain period of such change.
Individual
Michelle R. D'Antuono
Ingleside Ccogeneration LP (Occidental Chemical Corporation)
No
Yes
Ingleside Cogeneration appreciates the rapid development team’s effort to ensure that MOD-032-1’s data specifications are consistent with existing regional requirements. The industry has generally settled on a modeling structure that includes steady-state, dynamics, and short-circuit data – and the specific elements are appropriate to the needs of the planning function. Although they will not affect our positive vote, we would like to raise two logistical concerns that the drafting team should consider. First Planning Coordinators should identify those items in their data specifications that correspond to Attachment 1. We anticipate that Compliance Enforcement Authorities will ask downstream data suppliers such as ourselves to prove that every line-item was satisfied. PCs may use different language to describe a modeling parameter for a variety of very good reasons – and the Attachment 1 elements may be hidden in a much larger reporting template. They should make the connection up front, so that we are not left in the position to do so. (It seems logical that PCs would need to do so anyways to demonstrate their compliance with MOD-032-1 R1.) Secondly, Planning Coordinators should provide the latest data they have on hand when the data template is issued. This would eliminate any uncertainty about the accuracy of data in the PC’s database versus that which was supplied (i.e.; due to a data entry error or some other cause). In addition, it offers the opportunity to request a reason for any parameter that has changed in the interim – which may be useful reliability information as well.

Yes
Ingleside Cogeneration agrees with the approach the rapid development team has taken to validate wide-area planning models. The Planning Coordinator relies most heavily on the performance data provided by Reliability Coordinators and Transmission Operators to improve model accuracy – and traditionally has worked closely with those entities in this regard. In addition, we believe that the PC and/or TP has other enforceable recourse to bring in other downstream entities if needed. In particular, the Generation Validation standards that are pending FERC's approval already call for the verification of complex governor and excitation systems in response to frequency and voltage transients. This should be sufficient to assure that the PC's wide-area models have the best generator-related information available – and further GO requirements are not needed.
Individual
Roger
Dufresne
No
Yes
We do not have found requirement equivalent to this in MOD-032-1: MOD-013-1 R1.2.1. Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.
Yes
Individual
Brett Holland
Kansas City Power & Light
Agree
Florida Municipal Power Agency
Individual
David Jendras
Ameren
No
No
With respect to the applicability of this standard, we have concerns regarding the replacement of the Regional Entities with the PC in the standard. In addition to taking time for the PC's to ascend the learning curve associated with collecting, testing, and forwarding the data to the ERO or its designee (responsible for assembling the final interconnection models) if they have not been involved with this process to date, the opportunities for seams issues to occur would be significant and ongoing, with the rearrangement of roles to replace 8 regions with ~50+ PC entities. R2: We believe that without a uniform data standard the quality of the data may decrease. Using the Region as a collection point has merit in ensuring that the data requirements are consistent. Therefore, it would be preferable to retain the Regional Entities in the process as at present. R3: A major concern involves consistent and comparable data submitted. We believe that removing the Regional Entities as the collectors will necessitate development of a procedural manual that all must follow to assure workability of the model assembly process. R5: We request that Language is included in the standard to reflect that the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection

models, and should provide the procedural manual for assembly of model data to insure consistency and usability of the models. This would help address concerns raised regarding consistency of data mentioned in our comment to R2. We request that the range of time values shown under the VSL's for draft standard MOD-032-1 R3 should match those shown for the existing MOD-010-1 R2 or MOD-012-1 R2.
Yes
We request the SDT to provide additional clarification regarding what would constitute a 'dynamic local event' as cited in R1.2?
Group
SERC Planning Standards Subcommittee
Jim Kelley
No
No
MOD-032-1: R1 We have concerns regarding replacement of the RRO with the PC in the standard. In addition, with the learning curve time associated with testing and forwarding to those finalizing models the opportunities with seams issues seem significant and possibly on-going with the increase of PCs involved. Therefore, it would preferable to maintain the Region in the process as at present. R2. It appears that without a uniform data standard the scope of the data may not be uniformed. Using the Region as a collection point has merit in ensuring that the data requirements are consistent. R3. The concern centers on consistent and comparable data submitted. Removing the Regions as the collectors may necessitate development of a guideline manual that all accept to ensure that data is consistent. R5. The SDT is requested to include clarification language that the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection models, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection models, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection models and each will provide a procedural manual for their area to ensure data submittal is consistent.
Yes
The SDT is requested to review the other MOD standards to ensure that GOs are covered and required to submit data when requested. The comments expressed herein represent a consensus of the views of the above named members of the SERC PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Denise Yaffe
Southern California Edison
No
No
SCE appreciates the standards drafting team's effort to integrate six existing data modeling standards into two concise. MOD-032-1 and MOD-033-1 are good starting points in this effort, but additional clarifications and refinement are necessary before they can be supported. For example, MOD-032-1, R4.1 includes a provision under which Planning Coordinators and Transmission Planners might be required to use erroneous data so long as the party providing the data was able to provide some type of technical explanation supporting its use. The Planning Coordinator and Transmission Planner should have the ability to reject data when they find deficiencies with the data provided to them.
Yes

A validation standard that allows the Planning Coordinator to identify potentially inaccurate models and develop its own criteria or threshold for the identification of potentially incorrect models is the right step for a NERC standard. Thank you.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, on behalf of its NERC registered affiliates. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. 1. Comments: Is it the intent for these standards to address: Operating as well as Planning Models? Models used for EOP-005 Blackout recovery analysis requirements? What is the relationship between MOD-032 & 33 and the TOP-2 and VAR-2 requirements to report short term MW and MVAR limitations and FAC-008 ratings? Should they be consolidated in these requirements similar to pulling transformer data reporting requirements from VAR-002?
No
GO requirements in MOD-010, 11, 12 and 13 are presently well-defined and reasonable in scope. MOD-032 proposes to leave the type of model, level of detail, size cutoffs (if any), case types and scenarios to be established at some future time by the Planning Coordinator. This creates uncertainty because it requires approval of a standard without all of the relevant provisions being known. The request for station service auxiliary load (for new plants) information in Attachment 1 of MOD-032 may not provide sufficient reliability benefit to cover the cost. For example, an extremely complex algorithm would be needed in some cases to relate this parameter to load level and other operating conditions (summer vs winter, limestone preparation on vs off etc.), and it is doubtful that developing detailed inputs in this respect would have a meaningful impact on system stability analyses. The proposed approach could also lead to unjustifiable regional variances. A mandate by the TP to supplement TGOV1 fossil models with an LCBF1 outer-loop representation may generally be reasonable, for example, but what is there to prevent a demand that the units be migrated and validated to the much-more-difficult TGOV5 model? All obligations should be clearly set forth in the proposed reliability standard when it is posted for voting. For example, the standard could require that the TP/PC reach agreement with the GO regarding required models. The 30-day deadline specified in R4 is far too short for independent GOs who, lack in-house modeling specialists and, would need to contract for the services needed to develop responses. The time limit should be at least 90 days. Mandating in Att.1 that GOs provide short-circuit data at the generator, GSU and transmission line should be accompanied by a requirement that the TO collaborate with the GO in transposing generator nameplate information to high-side values. We also recommend that the SDT consider the comments prepared by the Florida Municipal Power Agency (FMPA) with regard to principles of technical and economic justification.
Group
seattle city light
paul haase
Agree
Sacramento Municipal Utility District (SMUD)
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Florida Municipal Power Agency (FMPA)

(1) The proposed model validation process should be restricted to the validation of models concerned with the operating horizon, and not the planning horizon. Validating a planning horizon model with past operating data is not an efficient use of time and will deliver only de minimis benefits, if any at all. (2) Requirement R2 in proposed MOD-033-1 is redundant with current requirements under Standard IRO-010-1a and pending Requirements in TOP-003-2 for requesting operating data. Therefore, if an entity forgets to submit operating data for validation, that entity could be found liable under three separate Standards. All requests for operating data should be confined to one Standard. (3) The language "too large" in Requirement R1.3 is vague and the Application Guidelines do not assist with defining what "too large" entails. Please clarify this language in the Standard itself. (4) Is the Application Guidelines section of the Standard primary law or is it mere suggestive guidance. For example, the Requirement R1 section of the Application Guidelines states that when "performing the comparison required in part 1.1., the PC should consider, among other criteria: (1) System Load; (2) Transmission topology and parameters; (3) Voltage at major buses; and (4) Flows on major transmission elements." (emphasis added). If a PC were not to consider any of the above criteria, would it be found in violation of R1.1? It appears not as the term "should" as opposed to "shall" was utilized. In addition, if any criteria, quantitative or qualitative, are later drafted into the Standard, why can't the Standard Drafting Team include them in the Requirements as opposed to the Application Guidelines section?
Individual
Kayleigh Wilkerson
Lincoln Electric System
MRO NSRF
No
Although supportive of the overall objectives in developing MOD-032-1, LES is concerned by the lack of a detailed plan on how the eastern interconnection cases would be developed going forward. Additionally, there is no proposed plan on how to build the regional power flow and dynamic cases or whether these regional cases would even be built any longer once MOD-032-1 is an enforceable standard. Although Requirement R5 requires each Planning Coordinator (PC) to submit data to the ERO or its designee to support creation of the interconnection models, the PCs have no obligation to collect data on the same schedule and no obligation to build the same set of models. Per the Rationale for R5, MOD-032-1 assumes that "entities are successfully coordinating their efforts" thereby negating the need to establish a process for building the larger interconnection-specific model. However, the drafting team fails to account for the existing regional processes that currently ensure successful coordination which would potentially be eliminated pending the standard's approval.
Individual
Diane Barney
New York State Departement of Public Service
It is premature to be voting at all for the standard at this point in the process. Two major pieces of information are missing. First, the SAR has not been adopted, so we do not know if the proposed standard conforms to an adopted SAR. Second, the proposed standard was drafted by a small team of subject matter experts and has not yet been subject to a NERC wide critical review. Therefore, we do not yet know if there is a fatal flaw in the standard for some system(s) across NERC not represented by the SMEs, or if there is an outstanding idea to improve the draft standard.

It is premature to be voting at all for the standard at this point in the process. Two major pieces of information are missing. First, the SAR has not been adopted, so we do not know if the proposed standard conforms to an adopted SAR. Second, the proposed standard was drafted by a small team of subject matter experts and has not yet been subject to a NERC wide critical review. Therefore, we do not yet know if there is a fatal flaw in the standard for some system(s) across NERC not represented by the SMEs, or if there is an outstanding idea to improve the draft standard.
Individual
dmason
HHWP
No
Yes
Each Planning Coordinator must submit the data provided to it under Requirement R3 to the ERO or its designee to support creation of the interconnection model(s) that includes the Planning Coordinator’s planning area as follows: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]. The reliability related need for this data to be provided to the ERO is not clear. This data and the creation of Interconnection wide model should not be an ERO function. It is more properly a Planning Coordinator function
Yes
Individual
Steven Mavis
Southern California Edison
Yes
SCE appreciates the standards drafting team's effort to integrate six existing data modeling standards into two concise. MOD-032-1 and MOD-033-1 are good starting points in this effort, but additional clarifications and refinement are necessary before they can be supported. For example, MOD-032-1, R4.1 includes a provision under which Planning Coordinators and Transmission Planners might be required to use erroneous data so long as the party providing the data was able to provide some type of technical explanation supporting its use. The Planning Coordinator and Transmission Planner should have the ability to reject data when they find deficiencies with the data provided to them. Please see SCE's completed comment form for additional comments.
Yes
SCE appreciates the standards drafting team's effort to integrate six existing data modeling standards into two concise. MOD-032-1 and MOD-033-1 are good starting points in this effort, but additional clarifications and refinement are necessary before they can be supported. For example, MOD-032-1, R4.1 includes a provision under which Planning Coordinators and Transmission Planners might be required to use erroneous data so long as the party providing the data was able to provide some type of technical explanation supporting its use. The Planning Coordinator and Transmission Planner should have the ability to reject data when they find deficiencies with the data provided to them. Please see SCE's completed comment form for additional comments.
SCE appreciates the standards drafting team's effort to integrate six existing data modeling standards into two concise. MOD-032-1 and MOD-033-1 are good starting points in this effort, but additional clarifications and refinement are necessary before they can be supported. For example, MOD-032-1, R4.1 includes a provision under which Planning Coordinators and Transmission Planners might be required to use erroneous data so long as the party providing the data was able to provide some type of technical explanation supporting its use. The Planning Coordinator and Transmission Planner should have the ability to reject data when they find deficiencies with the data provided to them. Please see SCE's completed comment form for additional comments.

Yes
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Individual
Jay Teixeira
Electric Reliability Council of Texas, Inc.
IRC SRC
No
Yes
In R1.1 Attachment 1, the following “At a minimum” data reporting requirements should be added: For Steady-State: Add to item 2 Aggregate Demand at each bus: Add item 2d, Load Characteristics – specify percent large motor, small motor, resistive, discharge lighting, other of load at bus. Add to item 3 Generating Units: Collector system data showing positive, negative, and zero sequence data for equipment below the transmission level step up transformer. For wind farms and similar widespread equipment, this would be the collector system showing complete feeder circuits to pad-mount transformers on each turbine. For wind turbines – add specification of turbine type such as type 1, 2, 3, or 4. Add to item 4 AC Transmission Line and 6 Transformer: 4b and 6h. ratings – add other specified ratings such as 15 minute and conductor/transformer emergency ratings. For Short-Circuit: For item 1 Positive Sequence – add for both saturated and unsaturated For item 2 Negative Sequence – add for both saturated and unsaturated For item 3 Zero Sequence – add for both saturated and unsaturated Add to item 3b (Generator) and 3d (Transformer) under Zero Sequence data: Add grounding type and ground equipment such as neutral transformer with resistor value with appropriate data to convert to specified per unit quantities. Add new item after item 4 to request controlled fault current limits for sub transient, transient, and synchronous time periods for type 3 without crowbar and type 4 wind turbines. Add new item after item 4 to request Direct Axis Subtransient, Transient and Synchronous reactance both saturated and unsaturated.
Yes
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC Planning Standards Subcommittee
Group
NAGF Standards Review Team
Patrick Brown

Yes
1. Is it the intent for these standards to address Operating as well as Planning Models? Models used for EOP-005 Blackout recovery analysis requirements? 2. What is the relationship between model standards and the TOP-2 and VAR-2 requirements to report short-term MW and MVAR limitations and FAC-008 ratings? Should they be consolidated in these requirements similar to pulling transformer data reporting requirements from VAR-002? 3. The GOP might also be included if short-term limits are in the scope of this standard. 4. Detailed Description add "and when changes to equipment are made during the life of the plant" to the sentence "Generator Owners must provide accurate model data of their systems during the interconnection process". This is inferred in R3 of MOD-32. This may also need to cover any pre-change notifications required outside of an interconnection request for existing units that are changing modeled equipment but not doing uprate changes. 5. It's not clear what the issue is with Proprietary Models if it is understood that the GOs must supply a model that has been validated against commissioning test data. I understand this was an issue for early winds farms but efforts have been made to develop standard wind models for different designs. Is this really a failure during the interconnection process and should be addressed in the FAC-001/2 standards related to new generation?
No
1. The SRT questions the reliability based need for R5.2. We believe that the scope of the documentation should be narrowed to only include major data modifications that could affect the model. To include all data modifications would create an unnecessary administrative burden on the PC. Another suggestion would be to add a requirement that the ERO or its designee request this type of documentation, similar to R4, as part of the model building process. 2. GO requirements in MOD-010, 11, 12 and 13 are presently well defined and reasonable in scope. MOD-032 proposes to leave the type of model, level of detail, size cutoffs (if any), case types and scenarios to be established at some future time by the Planning Coordinator. This constitutes asking us to issue a blank check regarding compliance burden, which is unbusiness-like. 3. Indications of excessive scope creep are already evident in Attachment 1 of MOD-032, e.g. station service auxiliary load (for new plants). An extremely complex algorithm would be needed in some cases to relate this parameter to load level and other operating conditions (summer vs. winter, limestone preparation on vs. off etc), and it is doubtful that developing detailed inputs in this respect would have a meaningful impact on system stability analyses. 4. The proposed approach could also lead to unjustifiable regional variances. A mandate by the TP to supplement TGOV1 fossil models with an LCBF1 outer-loop representation may generally be reasonable, for example, but what is there to prevent a demand that the units be migrated and validated to the much-more-difficult TGOV5 model? All obligations should be forthrightly put on the table at the time a standard is posted for voting. 5. The 30-day deadline specified in R4 is far too short for independent GOs who, lacking in-house modeling specialists, would need to contract for the services needed to develop responses. The time limit should be at least 90 days. 6. We also recommend that the SDT consider the comments prepared by the Florida Municipal Power Agency (FMPA), especially as regards adhering to principles of technical and economic justification. 7. On R1: Uniformity of the data request form is desirable. R1 data requirements should be sensitive to the life cycle of the generator (age, data availability for pre-1970 units, units in various stages of project development, planning, and start up), or to unconventional data requests that would require reverse/extensive engineering techniques to fulfill. 8. R2 is purely administrative and should be eliminated. The PC should simply deliver the data requirements and reporting procedures to the BAs, GOs, and TOs. etc. once they have developed or revised them. 9. Attachment 1 should provide additional details of precisely what "minimum" data is required - for example, on the generator, which time constants and which reactances are required. 10. For the VSL on R3, perfect data submission is in violation (0% missing/unformatted/late is less than 25%) - please correct. Consider some minimum level of data shortage/formatting/tardiness being acceptable rather than instituting a "zero tolerance" position - say 5% up to 25% is the Lower VSL. A zero tolerance for a VSL seems inconsistent with the NERC Reliability Assurance Initiative and risk based compliance and enforcement approach. 11. For R4.2 - an explanation with a technical basis for maintaining the current data should be allowed here too (like R4.1). 12. Attachment 1, steady state, item 3c - station service auxiliary load data should be restricted to normal plant configuration for the GO 13. Attachment 1, steady state, item 3d - please define what is meant by "regulated bus". 14. Attachment 1, steady state, item

3e - is this the voltage schedule? 15. Attachment 1, steady state, item 3f - what value is the % ownership to the model? 16. Attachment 1, steady state, item 3h - please clarify what this means for generating units. 17. Attachment 1, steady state, item 6g - please explain what this rating is. 18. Attachment 1, steady state, item 9 - we believe that there should be a requirement for the PC to provide technically based reasons for expanding the data request beyond what is listed in Attachment #1. (Requirement 1, Attachment 1 - steady state, item 9). 19. We recommend R5 be removed from the draft standard altogether and that the PC deliver the data in response to a NERC Rules of Procedure Section 1600 data request. This requirement is purely administrative.
Individual
Patrick Farrell
Southern California Edison Company
No
No
SCE would like to thank those who have worked diligently during the MOD B informal standards drafting process. We strongly support the need for consolidating and updating the existing MOD standards with respect to data requirements and the specification of functional entity responsibilities. However, we are submitting a negative vote in hopes that the SDT will consider revisiting the intent of R4. While we recognize that the entity responsible for the data is ultimately the expert on their particular piece of equipment or facility, we believe the MOD standards intend to ensure the accurate and reasonable assessment of the interconnected electrical grid in order to ensure that long-term reliability is maintained and adequately planned. We recommend that the SDT revise R4 to include an additional sub-requirement to R4.1 which specifies that if the usability or data differences cannot be resolved between the identifying entity and the data owner, the PC or ERO may act as an arbitrator to propose a final modeling decision. Our intent is to ensure that a data owner may continue to stay in compliance by actively providing technically-adequate data AND that the usability of the larger, interconnected model will continue to serve within the original intent of the MOD standards. Our experience has shown that a technical justification may exist for equipment to be modeled in a certain manner, but that added detail or limitations of modeling software can detract from the overall simulation and study quality. Various system conditions and physical equipment design limitations will sometimes prevent a perfect mathematical model from being developed. SCE supports the elevated, system-wide perspective that the TP or PC would have as an appropriate measure of usability for study purposes and support any revision to R4 that reflects this wider-perspective expertise. We thank the SDT for the opportunity to comment and hope that a reasonable revision to MOD-032-1 can be developed which will support the spirit and intent of this comment.
Yes
SCE would like to thank the drafting team and NERC for providing the opportunity to comment on the new proposed modeling validation standard. We feel a validation standard that allows the Planning Coordinator to identify potentially inaccurate models and develop its own criteria or threshold for the identification of potentially incorrect models is the right step for a NERC standard.
Group
Puget Sound Energy
Eleanor Ewry
No
Yes
The approach of MOD-032-1 currently aligns with existing data collection practices.

R1.6 - It should be allowable for the Planning Coordinator to provide a schedule to the GO, LSE, RP, TO and TSP outside of the 13 month requirement. Within WECC, the Generator Testing Policy requires the GO to validate dynamic models every 5 years or when major equipment changes take place. The PC should be able to point to the RRO testing policy and timeline with language such as "...at least once every 13 calendar months or according to a schedule provided by the RRO." This would lessen the burden on the GO to provie annual updates for data that will not change that frequently and also allows for future flexibility with the proposed MOD-024 through MOD-027. R4 - Who will be the final authority if the PC or TP and the entity submitting data can not agree on a valid model? There should be a clause that the data shall be usable within the platform specified by the PC or TP.
No
There seems to be little technical basis for the requirements in MOD-033-1, specifically with regards to defining the types of events against which models need to be validated and how frequently this should happen.
R1.1 - The system power flow model for a Planning Coordinator Area may not change significantly enough to warrant validating the model every 24 months. Is there a technical basis for choosing 24 months as the time period for which the system power flow model must be validated? Also, it should not be up to each individual Planning Coordinator to determine the how large the discrepancy between the system model and actual system performance can be. This should be determined by the RRO or NERC based on sound technical reasoning. R1.2 - What would constitute a dynamic local event? This implies that it would not be required for the Planning Coordinator to validate dynamic models following a system-wide event. Will this be the responsibility of the RRO? What distinguishes a dynamic local event from a system-wide event (number of Planning Coordinator Areas impacted, amount of generation/load impacted)? These should become NERC defined terms.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
R4 requires a generator response to technical concerns within 30 days unless a longer time is agreed to by the requesting entity. IPPs, especially the smaller units, do not have full-time technical resources on staff to address this request. The process of identifying engineering contractors with the available resources, bidding the job, receiving manufacturer technical support for the questions, and developing and submitting a response is likely to take well beyond 30 days. Suggest changing the language to 90 days, or to "or such time as proposed by the entity, if there is a submitted technical reason why a longer time period is required to address the concern". Under "at a minimum" requirements, there is no valid reason to require percentage of ownership. R1 should be changed to require a technical justification for expanding the "at a minimum" requirements, to prevent requests for data which add little to the model, but impose costs on the entities who receive the request.
Yes
Individual
Silvia Parada Mitchell
NextEra and FPL
Yes
NextEra believes that any consolidation of the MOD Standards needs to also consider that the working groups associated with the subject matters are, in most cases, different staff members e.g. Planning (steady state), Protection & Control (short circuit), Stability experts (dynamic cases). Therefore, the merging these standards must include organizational framework that separates specific subjects in the new Standard(s), otherwise the Standards will create unintended inefficiencies. NextEra Energy is

encouraged by the direction of MOD-032-1, but believes that it needs considerable refinement, including technical corrections, prior to becoming a mandatory Reliability Standard. These comments are provided to assist the Standards Drafting Team refine MOD-032-1 so that it may be both technically correct and clear.
1. Revise R1.1 to read as follows: “1.1. Specification of the required data listed in Attachment 1;” It is not good drafting practice and there is insufficient technical rationale for the inclusion of “at a minimum.” If the Standards Drafting Team desires a Planning Coordinator to in its own discretion consider other data, it better serves stakeholders to draft a technical guidance paper to suggest the consideration of other data than to do so via a mandatory requirement. Further, such a drafting practice is inconsistent with several of the Ten Benchmarks of an Excellent Reliability Standard (e.g., measurability no. 4, clear language no. 8). Thus, NextEra recommends that “at a minimum” be deleted. 2. Delete R2. The rationale for this requirement is that a change in ownership may necessitate the need for the Planning Coordinator to provide its data to a “Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider.” This rationale is supposition and insufficient to include as a mandatory requirement. Further, it implicates a commercial matter; a change in ownership includes contractual obligations, which is a better place for the consideration of the need to exchange data than a mandatory requirement. Further, inclusion of R2 implicates P81 criteria. P81 Criterion A states “The Reliability Standard requirement requires responsible entities (“entities”) to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.” R2 satisfies Criteria A in that it is a requirement that is related to a generalized concern related to data exchange, and not specific performance or operational issue. Further, this requirement also implicates Criteria B 1 (administrative), 2 (data collection/data retention), 3 (documentation), 4 (reporting) and 6 (commercial) of P81. There is no rationale provided why there needs to be a legal requirement to provide data in the manner set forth in R2. Moreover, data exchanges such as the one prescribed in R2 can be accomplished via the regional planning committees or a simple phone call, which is another reason not to mandate such via a Reliability Standard. For all the forgoing reasons, R2 should be deleted. If the SDT believe this is an issue that should be addressed in some manner, NextEra recommends it issue a good business practice document. 3. Delete R5. Requirement 5 is a data submittal requirement that satisfies the P81 Criteria A and B 1 (administrative), 2 (data collection), 3 (documentation) and 4 (reporting). In the P81 filing before FERC similar data requirements were deleted from other Standards, therefore, it is counterproductive and contradictory to the P81 efforts to include R5 in the Standard. If the SDT believes this data is important for the ERO to obtain, it should be accomplished via a Section 1600 data request, as the Misoperations SDT determined for Misoperations data to be provided to the ERO. 4. Attachment 1 should not include all the data listed and the language should be clearer. a. For the same reasons set forth in response to R1.1, the “at a minimum” language is inappropriate for Attachment 1. b. Steady state (SS) 2c. load type load type data is not required for planning studies and thus should be deleted as technically incorrect. Also, 2c specifies “etc.” which should be deleted as “etc” is not appropriate drafting practice for mandatory Reliability Standard. such a drafting practice is inconsistent with several of the Ten Benchmarks of an Excellent Reliability Standard (e.g., measurability no. 4, clear language no. 8). Thus, NextEra recommends that “etc” be deleted. c. SS 3c. plant aux load is netted with generation, thus the Transmission Planner will know the net generation; therefore, it is not necessarily to include the “aux load” and it should be deleted. d. SS 3h share of reactive contribution for voltage regulation. This refers to PSS/E RMPCT data value that is optional. RMPCT may be useful for some, but may also cause problems when plant dispatch changes and RMPCT no longer add to 100. e. SS 3j. prime mover type is not needed for planning studies; therefore, inclusion of prime mover type is technically incorrect and should be deleted.
No
NextEra Energy is concerned with the direction of MOD-033-1. While NextEra acknowledges that FERC directives are associated with MOD-033-1, it strongly recommends that the Standard Drafting Team and NERC Staff reconsider its approach to addressing the FERC directives. The primary concern is related to the how the term validation is defined and the clarity on the amount of flexibility or discretion provided to entities to develop a process to validate. The challenge associated with these issues seems to be to be acknowledged in the rationale for R1 that states in part “Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language.” The following are general comments that provide a basis for NextEra’s overarching

concern that the direction of MOD-033-1 needs to reconsidered. • The proposed MOD-033 requirements for validation of dynamic models grossly underestimate the amount of work required for these analyses. Attempting to recreate an event with dynamic simulation studies is an extremely complex undertaking that may require input from transmission operators and reliability coordinators throughout the interconnection and can take more than a year to perform. The scope, complexity and need for the analysis is dictated by the event. While power systems experience outages on a daily basis, very few of these events cause enough of a perturbation to reveal significant dynamic response; consequently mandating a validation effort every two years will force a large level of engineering effort with questionable benefits. • Differences between recorded system response and dynamic models response are difficult to associate with a specific model due to the manner in which generators affect each other throughout the interconnection. For example is a voltage dip at station C due to the behavior of nearby generator A or nearby generator B or is it due to load behavior. Cause and effect are only clearly delineated in generator open circuit tests when the generator is disconnected from the power system. • The validation requirement applies to Planning Models but Planning Models cannot be used to validate actual system events because Planning Models correspond to a best guess of a future point in time and assume normal facility availability e.g. does not account for temporary system clearances. • Planning Models would first need to be converted to represent conditions at the time of the event. System response tends to be strongly influenced by initial conditions. Converting a Planning Model to the initial condition for an event is extremely laborious. Cooperation of all utilities is required to collect and provide system condition data at the time of the event. Once this large volume of data is assembled, it can take a team of engineers two to three months to convert the Planning Model. • The idea that Planning Models can be adjusted to exactly match recorded system response is false. If one is successful in identifying aspects of the Planning Model that lead to divergence from observed BES response, it may be possible to improve the match. An exact match is beyond the realm of possibility. Compliance metrics for validation are therefore not suitable. • Benchmarking a system event and adjusting models to improve accuracy is an extremely labor intensive engineering process that requires the highest level of engineering expertise. Requiring this exercise every 2 years will be extremely burdensome to the industry if not impossible • Most system events do not cause system perturbations large enough to reveal significant characteristics of dynamic response. Biennial analysis of mild disturbances will consume large amounts of engineering manpower analyzing events that reveal little of the BES actual character. • The scope and type of dynamic analysis varies greatly and depends on the nature of the event. Analysis of large scale events that do reveal significant dynamic response already occurs in accordance with ERO efforts or directives. These efforts should be encouraged but are not suitable for compliance enforcement. • Improvements in dynamic model accuracy would be expected with the generator verification tests called for in the proposed MOD-026 Standard. • Reliability Coordinator should be responsible for the R1.1 that deals with comparing steady state models to recorded system behavior. Operating Horizon steady state models would be used for this as the model topology, loads and dispatch should be much closer to the system conditions at the time of an event. Choosing the Planning Coordinator as responsible means the starting point would be Planning Horizon models that require more extensive analysis and modifications to match them to event conditions. Based on these concerns, recommend re-writing R1 And its sub-requirements as follows: R1. Each Reliability Coordinator must implement a documented process that validates, to the extent reasonably possible, through a bandwidth or tolerance level approach the data used for steady state (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses or simulations of actual system response that includes the following items: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. A simulated validation through a bandwidth or tolerance level approach of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other real-time data sources to check for system significant discrepancies that the Reliability Coordinator at least once every 24 calendar months.

Recommend re-writing R1 And its sub-requirements to be limited to the following and read as follows: R1. Each Reliability Coordinator must implement a documented process that validates, to the extent reasonably possible, through a bandwidth or tolerance level approach the data used for steady state (the data submitted under MOD-TBD-01 (the single modeling data standard)) for its planning area against actual system responses or simulations of actual system response that includes the following items: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.1. A simulated validation through a bandwidth or tolerance level approach of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other real-time data

sources to check for system significant discrepancies that the Reliability Coordinator at least once every 24 calendar months.
Individual
Anthony Jablonski
ReliabiltiyFirst
ReliabilityFirst votes in the affirmative because the draft standard establishes consistent modeling data requirements and reporting procedures to support analysis of the reliability of the interconnected transmission system. ReliabilityFirst offers the following comments for consideration: 1. Requirement R5 - Requirement R5 states that the PC shall submit data to the ERO's designee for interconnection models. In the Eastern Interconnection (IE), the ERAG MMWG builds the interconnection cases utilizing Regional Entity (RE) staff. Some of the Regional Entity's may pull out of this process once these standards are approved as there is no requirement for them to support it. The Planning Coordinators are under no obligation to supply funds or build interconnection models, only to submit the data. Currently the six RE's in the EI share the cost of building the models. ReliabilityFirst recommends that NERC should name their designee in the EI, well in advance of the approval of these standards to ensure a smooth transition. 2. General Comment – ReliabilityFirst recommends the drafting team develop a mapping of Registered Entities to their respective Planning Coordinators. A number of entities may not necessarily know who their associated Planning Coordinator is.
Group
ISO/RTO Standards Review Committee
Greg Campoli
No
The format of MOD-032 may be an issue given that: R1 requires "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area..." The highlighted phrase is not a defined/measureable mandate. Moreover the phrase is not required (the phrase is more of a good/best practice) and has the potential to invite subjective concepts if one or more of the TPs are not satisfied with the "level" of inclusion it gets. The SRC would suggest deleting the phrase "in conjunction with each of its Transmission Planners" The SRC suggests M2 be rewritten to make clear who "it" is in the phrase "... a statement by the PC that IT has not received a request for ITS data requirements...." M2 clearly refers to the PC but the phrase in question implies that the receiving entities are involved they are asking for data. It would be better if the phrase in question were rewritten to "... a statement by the PC that the PC already had all of the data required to meet R1." R3: The last sentence states "For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient." This statement is not needed since it is not a requirement. It is a measure of compliance, which is already adequately captured in Measure M3. R4: The phrase "including the technical basis or reason for the technical concerns," implies that the PC is required to provide this in the written notification but there is no such a requirement stipulated anywhere. If this is not a requirement, then it does not add any value to Requirement R4 as this requirement itself stipulates the tasks required of the Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider upon receiving a notification from the PC. R5 requires "Specification of the case types or scenarios to be modeled..." This requirement is formatted as a "fill-in-the-blanks" requirement, a format that FERC asked the Industry to avoid. The requirement asks the PC to fill in which cases are run. This would not result in a common North American assessment of conditions. The SRC would suggest that the basic set of cases be defined and thereby leaving the PS's to run any additional cases it deems as

appropriate. R5 requires data submission to the ERO "... to support creation of the interconnection model(s)". The requirement to supply data to the ERO is already required by the Rules of Procedure and need not be repeated here as a reliability requirement. Given the fact that the Requirement is not specific about which data/which study(ies) are envisioned it makes more sense to rely on the Rules of Procedure. The SAR alludes to interoperability issues among vendor-supplied programs. The SRC raises the concern that the ERO "program" may require data/formatting that is inconsistent with the entities data base. Here again the idea of placing a mandate on an asset which may change instantaneously (today its uses program A and tomorrow they use program B). One is deterministic and the other is probabilistic. Such transitions could prove costly to address. The SRC would ask if this requirement addresses a major area of concern or if it addresses a small subset of outliers? If it is a small subset, then the SRC would ask the SDT to consider a Dispute Resolution alternative. If an entity does not provide requested data, then the PC and Entity must go to a DR session to get the matter resolved.
The SRC believes it would be helpful to clarify the meaning of the word "validation". Is a PC compliant if it has a program "designed to represent conditions" or must the PC have a program that duplicates or can be made to duplicate actual conditions. The former approach does not punish the PC if the program fails to meet an Auditor's view of accurate results. The latter approach may result in PCs being required to simulate a state that cannot be duplicated.
Group
SPP Standards Review Group
Robert Rhodes
No
The SAR and overall scope of the project are satisfactory.
Yes
We suggest that the drafting team consider the following rewrite of the SEVERE VSL for R2: The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them in greater than 75 calendar days. Or, the Planning Coordinator did not provide its data requirements at all.
Yes
We have a concern regarding specifically which models are to be validated against the Real-time data. This should be specifically spelled out in the standard. Transmission Operator is missing in the 6th line of M2. M2 should read '...or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation...'.
Individual
Nazra Gladu
Manitoba Hydro
Yes
(1) SAR, Brief Description - replace " BPS " with " Bulk Power System (BPS) " as this is the first instance of this term in the document. (2) Manitoba Hydro believes that there is no discerning the owner of operational models vs. planning horizon models. The PC should not be responsible for the operational models (current year models). (3) Manitoba Hydro believes that even though the PC can create Planning Horizon models for it's region, they cannot build a 'standalone' model to perform studies without the coordinated efforts of external entities within the planning horizon (ie. interconnection models). (4) The ERO or designate standards/process is unidentified for the interconnection model (ie. bus numbering sequence, area ownership, transactions etc.).
Yes
No comment.

No
(1) General Comment - replace “ Board of Trustees ” with “ Board of Trustees’ ” throughout the applicable documents/standards for consistency with other standards.
(1) Guideline and Technical Basis - add the bracketed acronym (PC) following the first instance of the words “Planning Coordinator”. Moreover, subsequent instances of these words should be replaced with their acronym “PC”. (2) General Comment - replace “ Board of Trustees ” with “ Board of Trustees’ ” throughout the applicable documents/standards for consistency with other standards. (3) Manitoba Hydro believes that there is no discerning the owner of operational models vs. planning horizon models. The PC should not be responsible for the operational models (current year models). (4) Planning Horizon models are built within certain parameters (summer peak, generation conditions, future generation and transmission projects) and utilize ‘Best Guess’ parameters for future facilities and therefore cannot be used as ‘validated models’. Operational models are more suited for tasks of model validation as they more closely represent near term system topology. Also, there are no guidelines to suggest an ‘industry standard’ on manipulating data (load, generation, area transactions and losses) for analysis of a system event.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
For the SAR, p8, sect e., citing wind and PV resource equipment that is already interconnected, AECI questions whether this project's goal of mandating data-sharing can actually serve to override legal non-disclosure agreements that have already been executed between utilities and manufacturers.
Yes
(1) AECI definitely appreciates the phased-approach to implementation of MOD-032-1. (2) We do wish the SDT had provided separate ballots for MOD-032 and MOD-033, so we could have been affirmed this draft while withholding affirmation of MOD-033. (3) Because we are SERC members within the Eastern Interconnection, our understanding of MOD-032-1 R5 impact, is hazy at best.
No
FOR: MOD-033-1 R1.2 REPLACE: "through simulation of the next dynamic local event" WITH: "through simulation of their latest dynamic local event older than 24 months" OR WITH: "through simulation of their next oldest dynamic local event that is older than 24 months" RATIONALE: the current wording requires that Planning Coordinators accurately predict their next dynamic local event, which is near impossible
Due to the complex nature of producing meaningful data validation tools, AECI appreciates this SDT's Implementation plan for MOD-033-1, having allowed for at least 3 years following approval before becoming effective. FOR: Project_2010-03_Implementation_Plan REPLACE: "within 24 calendar months after the Effective Date of MOD-033-1" WITH: "within 36 calendar months after the Effective Date of MOD-033-1" RATIONALE: Alignment of contradictory statements, where "New or Revised Standards", MOD-033-1, cites "on the first day of the twelfth calendar quarter after applicable regulatory approval".
Individual
Jack Stamper
Clark Public Utilities
No
Yes
I believe MOD-032-01 Attachnment 1 (column “Short-Circuit”) is vague on what elements it is actually referring to and offer the following suggested change in order to make it more clear: 1. Each applicable element listed in the “Steady State” column for TOs and/or GOs. Those elements are

Buses, Generating Units, AC Transmission Lines, DC Transmission lines, Transformers, Shunt Capacitors, Reactors, and Static VAR Systems. a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data d. Mutual Line Impedance Data (TO only) I believe this not only makes it more clear but also places the information request in this column into a similar format as the other two columns in Attachment 1.
Yes
MOD-033-1 Requirement 1 referes to the single modeling data standard as MOD-TBD-01. Shouldn't this refer to MOD-032-1? Since MOD-032-1 is now subject to the baloting process it seems reasonable to include a direct reference to this proposed standard. Whether MOD-032-1 passes or fails, MOD-033-1, Requirement 1 will need to be modified to refer to the correct single modeling data standard.
Group
PacifiCorp
Kelly Cumiskey
Yes
PacifiCorp maintains that this process seems out of synch. Approving a standard without approving the SAR first seems to indicate that the informal process is rushing the standards development without due diligence.
No
PacifiCorp supports the following comments: Requirements 1 from both MOD-014 and MOD-015 have not been mapped to the new proposed standard. Developing power flow and dynamic models are needed to perform the needed studies for FAC, PRC, and TPL standards. This would create a gap in the MOD standards. Which entity is developing models? There needs to be a standard directing an entity to develop models or a change in the NERC Rules and Procedures. Specific comments/questions below: Has ERAG acknowledged that they will be getting 51 raw data sets from the PCs (i.e. unsolved, incomplete data)? ERAG is not in the functional model and not subject to compliance. Can the PC's be responsible for modeling issues? The PC is really just a middle-man for the data, So it is not clear to PacifiCorp what value they bring by being included in the process? If one or more regions gets out of building models, is ERAG still the one to aggregate them? If ERAG is the region and they build the power flows is there a conflict of interest? Not everyone uses the PTI product "model on demand," as the tool the TO could use on behalf of the PC.
-PacifiCorp supports the request for clarification of item 4 of the Steady-State portion of Attachment 1 in MOD-032-1. Item 4 states, "AC Transmission Line or Circuit (series capacitors and reactors shall be explicitly modeled as individual line segments) [TO]." Why does the drafting team see the need to explicitly model series capacitors and reactors? This equipment is usually not breakered and, thus, from a contingency standpoint, is part of the line that it's connected to. Explicitly modeling series reactors and capacitors would provide misleading results when performing N-1 contingency analysis. Additionally, PacifiCorp supports the following comments provided by Florida Municipal Power Agency: -The SAR goes to great length to describe a purported problem with gaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement. -In an apparent attempt to avoid the need for a technical justification, the SAR states: "(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection." The Planning Horizon is strewn with similar unknowns that we cannot know (load models, generator dispatch, transmission construction), and this statement alone is not technical justification. However, accurate models may be needed for the Operating Horizon. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. -The terms of the Confidentiality Agreement (CA) are important to consider. These models are to be shared with all the planners within

an Interconnection. The SAR on page 5 states: “(p)roprietary models with details hidden from the user (‘black box’ models) or those models that cannot be shared across the Interconnection are not acceptable.” How will the terms of such a CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR’s claim that: “The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary”, and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those terms -This challenge also exists in existing approved standards, IRO-010 (currently mandatory) and TOP-003-2 (approved by BOT, awaiting FERC decision). If the RC or TOP make a request for that model in their data specifications, then the GOP (or other entity) must submit those models to the RC and TOP. The SDT ought to address the question, is there a Reliability Related need to ensure that proprietary models gathered at the TOP or RC level be shared across the interconnection. In the Planning Horizon, there is too much inaccuracy in other variables that the effect of the lack of proprietary models cannot be separated from the influence of those other variables; hence, the question ought to be answered from an Operating Horizon perspective. Does the lack of these proprietary models cause a benchmark of Operating Models to actual events to be unacceptably innacurate? -The proposed standard requires the submission of short circuit data for planning models. This data has limited utility in planning studies.
No
PacifiCorp supports the following comments: How are the PC's going to validate data, by range checking or in a power flow? With EMS data? Is there an EMS case that works in PSSE? The proposed standard does not provide any criteria or thresholds for use in determining whether a planning model is adequately validated. In the event that a model is determined to inadequately validated, the proposed standard does not provide a procedure for the PC and equipment owner to resolve issues with the model. Will the PC be required to report poorly validated models to the RRO? Many models are built for non-coincident peak time frames. As such, there would be many issues with trying to validate for a real-time event. The PC is not a real time entity. If the RC is required to provide data to the PC, PacifiCorp affirms that the wrong entity is tasked with performing the validation of data. The planning horizon models represent future system conditions, and validation of these models would likely occur after a given planning model has been retired. The PC has no obligation to verify data once it leaves its hands (i.e. sent to the ERO designee). The wrong model is being validated. By definition, Planning Horizon models cannot be accurate due to forecast error; hence, Operating Horizon models should be validated by the RC rather than Planning Horizon models being validated by the PC. After all, in order to validate a Planning Horizon model to a past event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an Operating Horizon model as a first step. [Frank Gaffney Florida Municipal Power Agency] The proposed standard has overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis. [Frank Gaffney Florida Municipal Power Agency] The models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator. [Frank Gaffney Florida Municipal Power Agency]
Group
Florida Municipal Power Agency
Frank Gaffney
No
Although FMPA appreciates the efforts of the informal development process, FMPA disagrees with the

construct of the proposed SAR and proposed standards. Below are the primary reasons for our Negative vote for both MOD B and MOD C projects, which are described in more detail below. 1. The wrong model is being validated. By definition, planning models cannot be accurate enough to benchmark to operational reality due to forecast error; hence, operating horizon models should be validated by the RC rather than planning horizon models being validated by the PC. After all, in order to validate a planning horizon model to a real event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an operating horizon model. 2. The proposed standard may have overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis 3. In order to relieve this overlap, MOD standards (which FMPA believes are unnecessary and are candidates for P81) should be limited to planning horizon data that differs from operating horizon data. 4. Hence, standards are not needed for Planning Horizon and planning data can be gathered equally efficiently or cost effectively through data requests (e.g., modifications to GADS, TADS, DADS) 5. The proposed standard puts entities in a position of choosing between not complying with the standard, or not complying with a Confidentiality Agreement STANDARDS ARE ALREADY IN PLACE FOR OPERATING HORIZON MODELING Standard TOP-002-2, R19 states: “Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations” (emphasis added). This requirement has been mapped to TOP-003-2 in the new version of the TOP standards filed at FERC in April and awaiting FERC’s decision. R1 of that standard states: “Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.” For operating horizon load forecasts, TOP-002-2, R3 states: “Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.” This requirement has also been mapped to TOP-003-2. IRO-010-1, R1 states: “The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area …” Hence, it is clear that the MOD standards in question should be solely for the Planning Horizon and should not be for the Operating Horizon to eliminate duplication. If the intent is to have the MOD standards apply to the Operating Horizon, then there would be multiple standards governing the same activity and FMPA would propose that the SAR be changed to modify IRO-010-1 and TOP-003-2 as part of this effort to eliminate confusion and double jeopardy. STANDARDS ARE NOT REQUIRED FOR PLANNING HORIZON MODELING The purpose of the SAR starts with a false assertion, that planning studies “depend on accurate mathematical representations of transmission, generation, and load”. FMPA takes issue with the term “accurate”. Planning models by definition cannot achieve the level of accuracy that the ad hoc team seems to desire because they forecast the future. Recognizing that most transmission planning models represent a single representative moment in time: • To accurately model load, we must know the weather (e.g., how much air conditioning load is on), we must know the time of day, the day of the week, the season, we must forecast macro- and micro-economics to predict load growth both at the macro level and by substation, we must know what types of devices are operating on customer’s premises (e.g., variable speed drives, compressors, motors, etc.) to develop an “accurate” representation of load dynamics, and numerous other variables beyond anyone’s control. Load modeling cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. • To accurately model generation, we must predict fuel prices to know what is dispatched (e.g., a dispatch order, as discussed in the draft SAR, is not “accurate”, who would have predicted that “fracking” would have caused gas combined cycle to be dispatched before coal?), we have to predict maintenance cycles and forced outages years in advance, we have to predict the weather because output of gas turbines change significantly with ambient temperature and humidity. We have to predict the impacts of clean air legislation and other environmental legislation on economic dispatch order. For renewables, we have to predict the weather, e.g., how much wind is blowing, how much sun is shining. And many more variables beyond anyone’s control. Generation cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. • To accurately model transmission, we must depend on transmission owners meeting their construction schedules, we are dependent on the moisture in the soil for accurate zero sequence impedance calculations of transmission lines, and other variables beyond our control. Although we have more certainty that the transmission system will be as we predict in the next few years than we do for load and generation, FMPA has direct experience of a major transmission line being cancelled dramatically impacting the study area. Transmission cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. Planning is an important component to reliability, but the goal of planning is not about accuracy. The goal of planning is to study a variety of possible futures, using a variety of types of studies at the choice of the planner, such as scenario analysis and reasonable worst case assessments as is embedded within the TPL standards, or stochastic analyses as are typically used for resource planning, to gain reasonable assurance that we are planning a system that can be reliability operated in the Operating Horizon. Spending too much effort on underlying data is wasted because the inaccuracies inherent in forecasting the future overwhelm other inaccuracies. For instance: • Whether a major generator is on-line or not overwhelms a data error for that generator • Whether the wind is blowing or not overwhelms the value of accurate stability models for those generators • Whether gas is at $3 / MMBtu and gas dispatches before coal, or $10 / MMBtu and coal dispatches before gas overwhelms a dispatch order provided • Whether a new major line gets built or not overwhelms a small error in impedance of that line. • And so on. Hence, there is no reliability related need for the level of “accuracy” desired by the ad hoc team in the Planning Horizon (there is a need for accuracy in the Operating Horizon, see prior section and requirement R19 of TOP-002-2 that requires accurate computer models). In the Planning Horizon, the best that we can do is gather entities best forecasts of the future. Mandatory data requests, such as modifications to DADS, GADS and TADS, are sufficient to gather that planning data and no standard is needed for the Planning Horizon. For Order 693 directives and Order 890 directives purposes, mandatory data requests are equally efficient or effective as a standard for planning horizon data. VALIDATION SHOULD BE DONE BY THE RC ON OPERATING HORIZON MODELS, NOT THE PC ON PLANNING HORIZON MODELS As described in the previous sections, Planning Horizon models cannot be accurate enough to validate. Operating Horizon models are the models that ought to be accurate enough to validate, especially the real-time, current day and next day models (seasonal models will lose accuracy). Hence, the models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator. There ought to be a feedback mechanism from the accurate Operating Horizon models to the Planning Horizon models, but that feedback mechanism does not require a standard. THE STANDARD PUTS ENTITIES IN A DILEMMA OF CHOOSING BETWEEN NOT COMPLYING WITH A STANDARD OR NO COMPLYING WITH CONFIDENTIALITY AGREEMENT(S) FOR SOMETHING THAT MAY NOT BE TECHNICALLY JUSTIFIED The SAR goes to great length to describe a purported problem with obtaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement. In an apparent attempt to avoid the need for a technical justification, the SAR states: “(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection.” As described previously, the Planning Horizon is strewn with similar unknowns that we cannot know, and this statement alone is not technical justification. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. The terms of the Confidentiality Agreement (CA) are important to consider if these models are to be shared with all the planners within an Interconnection. The SAR on page 5 states: “(p)roprietary models with details hidden from the user (‘black box’ models) or those models that cannot be shared across the Interconnection are not acceptable.” How will the terms of the CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR’s claim that: “The Generator Owner must also arrange to give the

proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary", and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those terms. Such a situation is not acceptable. If the proprietary models are determined to be important, then an effort to reverse engineer models is an alternative. For instance, a project to work with EPRI or similar research institute to develop models for wind turbines from major wind turbine vendors in a laboratory environment could be done presumably without violating any agreements. Such models could then become public domain and used within the Interconnection models. As another alternative, an effort to work with the vendors of the power system analysis software to allow confidential "black box" models to exist within the software itself so that the confidential model is not shared across the Interconnection when the model is shared, but is used within the Interconnection model, but kept confidential within the software, is another alternative. Our interpretation is that the SAR's assertion that "black box" models are unacceptable is because there is no such ability within the existing software; and hence, the models cannot be shared across the Interconnection.
No
Please refer to response in question 1
Please refer to response in question 1
No
Please refer to response in question 1
Group
Oklahoma Gas and Electric Co
Terri Pyle
No
Yes
OG&E requests that the drafting team consider the following rewrite of the SEVERE VSL for R2: The Planning Coordinator failed to provide its data requirements and reporting procedures according to Requirement R2 within 30 calendar days of a written request but did provide them in greater than 75 calendar days. Or, the Planning Coordinator did not provide its data requirements at all.
No
Planning models in essence are not accurate and it is based on a forecast at a particular point in time. Therefore, it is our concern that we are trying to validate the planning models against actual system responses. Actual system responses may be very different than the planning models. A variety of factors plays a role in determining the actual system responses – maintenance schedules changed, planned projects delayed, etc. We also have a concern regarding specifically which models are to be validated against the real-time data. This should be specifically spelled out in the standard. In addition, R1.3 does not provide a guideline on how large the discrepancy needs to be. Does it have to be the same margin of error for all seasons or vary by season? What is the acceptable amount of discrepancy? Transmission Operator is missing in the 6th line of M2. M2 should read '…or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation…'.
Group
Duke Energy
Michael Lowman
Yes
Table 2 of the SAR identifies the RC and TOP for deliverability for data. However, we do not see where

in MOD-032 this delivery of data occurs. Duke Energy suggests adding the GOP if short term limits are included in the scope of this standard. Duke Energy suggests rewording the second paragraph under SAR information to: “Generator Operators must provide accurate model data of their systems during the interconnection process and when changes to equipment are made during the life of the plant” for added clarity.
Yes
Duke Energy believes that Interchange Coordination between neighboring TSPs should be identified in Attachment 1. In addition, we believe that Attachment 1 should also include a similar data requirement to load for generator “in service status” and possibly a footnote or parenthetical that says the generation dispatched should be representative of expected real time operation of generation resources for the modeled conditions. Lastly, Duke Energy questions the reliability based need for R5.2. Duke Energy believes that the scope of the documentation should be narrowed to only include major data modifications that could affect the model. To include all data modifications would create an unnecessary administrative burden on the PC. Another suggestion would be to add a requirement that the ERO or its designee request this type of documentation, similar to R4, as part of the model building process.
Yes
Duke Energy suggests rewording R1.1 as follows: “Validate its portion of the system in the power flow model by comparing it to actual system behavior, represented by a state estimator case or other Real-time data sources to check for discrepancies that the Planning Coordinator determines would warrant such an analysis at least once every 24 calendar months through simulation.” Duke energy suggests increasing the time allowed between steady-state and dynamic simulations in R1.1 and R1.2 from once every 24 months to once every 36-60 months. Duke Energy seeks clarification from the SDT on what constitutes a “local” event in a dynamic local event. Is the “local” event regional or entity specific? We also seek clarification on how an auditor measures whether a PC has done enough validation to satisfy compliance obligations in R1. Duke energy suggests rewording R2 as follows: “Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator that has indicated a reliability-related need for the data within 30 calendar days of a written request. Examples of data include, but are not limited to:” - state estimator case(s) - other Real-time data (including disturbance data recordings) necessary for actual system response validation.
Individual
Larry Brusseau
MAPP
Yes
This process appears to be out of synch. Approving a standard without approving the SAR first. The informal process seems to be rushing the process without due diligence.
No
Requirements 1 from both MOD-014 and MOD-015 have not been mapped to the new proposed standard. Developing power flow and dynamic models are needed to preform the needed studies for FAC, PRC, and TPL standards. This is a gap in the MOD standards. This is gap is which entity is developing models? There needs to be a standard directing an entity to develop models or a change in the ‘Rules and Procedures’. Specific comments/questions below: • Has ERAG acknowledged that they will be getting 51 raw data sets from the PCs (i.e. unsolved, incomplete data)? • ERAG is not in the functional model and not subject to compliance, can the PC’s be responsible for modeling issues? • The PC is really just a middle-man for the data, so why even be in the process? What value is there? • If one or more regions gest out of building models, is ERAG still the one to aggregate them? • If ERAG is the regions and they build the power flows is there still a conflict of interest? MAPP as a PC has not been involved with the model development or data collection. We do not have the infrastructure to develop models; We need a long implementation time to put these facilities in place. Not everyone uses the PTI product ‘model on demand’, as the tool the TO could use on behalf of the PC. The first suggestion is a modification to the R1.5 text “R1.5. Specification of the case types or

scenarios to be modeled (for steady state and dynamic data sets); and…”. The second suggestion is a modification to the R2 text, replace “…in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures.” with “…in it s planning area within 30 calendar days of any data requirements and reporting procedure modifications.”. R2. Each Planning Coordinator shall provide its data requirements and reporting procedures developed under Requirement R1 to any Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures. Issue: Requirement 2 above is based on a “written request” for data requirements and reporting procedure while the comment states this would be expanded to modifications to data requirements and reporting procedure. We interpret this to mean that whenever there is a “modifications” to data requirements and reporting procedure, the entity will be required to resend this information to each requester within 30 days. Recommend the term “modifications” be removed.
We request clarification of item 4 of the Steady-State portion of Attachment 1 in MOD-032-1: 4. AC Transmission Line or Circuit (series capacitors and reactors shall be explicitly modeled as individual line segments) [TO] Why does the drafting team see the need to explicitly model series capacitors and reactors? This equipment is usually not breakered and thus from a contingency standpoint, is part of the line that it’s connected to. Explicitly modeling series reactors and capacitors would provide misleading results when performing N-1 contingency analysis. The SAR goes to great length to describe a purported problem with gaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement In an apparent attempt to avoid the need for a technical justification, the SAR states: “(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection.” The Planning Horizon is strewn with similar unknowns that we cannot know (load models, generator dispatch, transmission construction), and this statement alone is not technical justification. However, accurate models may be needed for the Operating Horizon. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. The terms of the Confidentiality Agreement (CA) are important to consider. These models are to be shared with all the planners within an Interconnection. The SAR on page 5 states: “(p)roprietary models with details hidden from the user (‘black box’ models) or those models that cannot be shared across the Interconnection are not acceptable.” How will the terms of such a CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR’s claim that: “The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary”, and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those . This challenge also exists in existing approved standards, IRO-010 (currently mandatory) and TOP-003-2 (approved by BOT, awaiting FERC decision). If the RC or TOP makes a request for that model in their data specifications, then the GOP (or other entity) must submit those models to the RC and TOP. The SDT ought to address the question, is there a Reliability Related need to ensure that proprietary models gathered at the TOP or RC level be shared across the interconnection. In the Planning Horizon, there is too much inaccuracy in other variables that the effect of the lack of proprietary models cannot be separated from the influence of those other variables; hence, the question ought to be answered from an Operating Horizon perspective. Does the lack of these proprietary models cause a benchmark of Operating Models to actual events to be unacceptably inaccurate?
No

How are the PC’s going to validate data, by range checking or in a power flow? With EMS data? Is there an EMS case that works in PSSE? Many Models are built for non-coincident peak time frames, there would be many issues trying to validate for a real-time event. The PC is not a real time entity; we would be validating the RC models (RC required to provide data to PC), seems the wrong entity is doing the validation. The PC has no obligation to verify data once it leaves its hands (i.e. sent to the ERO designee). The wrong model is being validated. By definition, Planning Horizon models cannot be accurate due to forecast error; hence, Operating Horizon models should be validated by the RC rather than Planning Horizon models being validated by the PC. After all, in order to validate a Planning Horizon model to a past event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an Operating Horizon model as a first step The proposed standard has overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis The models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator Please separate the Standards into separate ballots.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
Yes
1. The first suggestion is a modification to the R1.5 text “R1.5. Specification of the case types or scenarios to be modeled (for steady state and dynamic data sets); and…”. Since FERC Order 890 in February, 2007, much work has gone into the development of reliability standards, including requirements pertaining to short circuit data. Inclusion of short circuit data in the MOD-032 standard appears duplicative and will create an administrative burden to the industry that is not warranted. ATC recommends that the SDT revisit the impetus for including short circuit data in the proposed standard. While addressing the proposed MOD standards, the NERC Planning Committee’s System Analysis and Modeling Subcommittee (SAMS) has stated that providing short-circuit data should not be required for assembly into an interconnection-wide case, but there should be requirements for sharing amongst neighboring entities. That is a noble objective that ATC supports; however, neighboring entity coordination is covered under PRC-001 and will be expanded under the proposed PRC-027. Other standards, such as FAC-002 and the future TPL-001 also include requirements relating to short circuits. 2. The second suggestion is a modification to the R2 text, replace “its planning area within 30 calendar days of a written request for the data requirements and reporting procedures.” with “…in its planning area within 30 calendar days of any data requirements and reporting procedures modifications.”.
Yes
NERC posted this project for comments for both MOD-032-1 and MOD-033-1, and at the same time, set up one ballot to cover both MOD Standards which ATC feeels is a poor practice. Posting for one ballot does not allow the entity to favor one while not the other and visa versa. For future postings, please split the two MOD Standards into two separate ballots.
Individual
Laurie Williams
PNM Resources, Inc.
Yes
PNM recommends that NERC assist the Regions with defining what PC "areas" are. In the western United States, in areas that are not part of ISOs, the PC concept has not been clearly defined for

entities and the Region has not provided any specific guidance on what exactly constitutes a PC 'area.' Lack of specific guidance will create reliability gaps and audit difficulties as PC responsibilities increase.
Yes
PNM cast a negative ballot based exclusively on the language on R5.2 and the corresponding language related to R5.2 in the VSL. PNM would like the standard to clarify what "data modifications" would trigger the requirement to report to the ERO under this requirement. Additionally, the VSL requires "The Planning Coordinator submitted the required data to the ERO or its designee but failed to include documentation and reasons for any data modifications", which implies that any single data modification, regardless of how minor, must be explicitly reported to the ERO and that report must be accompanied by the reason(s) why the data item was changed. PNM seeks to clarify R5.2 by perhaps qualifying the data modifications that would be significant enough to trigger 5.2 reporting. PNM anticipates that the ERO/RRO reporting of "modifications" could be time consuming for both entities reporting and the ERO/RRO receiving this information and in many cases not contribute to increasing the reliability of the BES. PNM suggests a qualifier that would eliminate load changes at individual busses and perhaps other items that should not have to be individually detailed.
Yes
None
Individual
Spencer Tacke
Modesto Irrigation District
No
1. In MOD-032, there is a blurring of responsibilities between the Transmission Planner and the Planning Authority (i.e., Planning Coordinator). As many utilities have no officially designated Planning Authority (Coordinator), this could be a problem. 2. The specific model data required (R1.1) is apparently detailed in Attachment 1, which does not seem to exist.
No
1. In MOD-033, there is a blurring of responsibilities between the Transmission Operator and the Planning Authority (Coordinator). As many utilities have no officially designated Planning Authority (Coordinator), this could be a problem. 2. The specific requirement (R1.1) for use of a State Estimator or equivalent, is not practical, as many smaller utilities cannot afford one nor justify the need for one in their normal day-to-day operations. 3. The specific requirement (R1) that the Planning Coordinator (Authority) "validate model data used for steady state and dynamic analyses for its planning area against actual system response" is not always possible, as the local planning area simulated response is not only dependent on the accuracy of the local planning area equipment models, but also on the accuracy of the adjacent planning areas equipment models, too.
Individual
Teresa Czyz
Georgia Transmission Corporation
No
No
R1 – At present, data requirements and reporting procedures have already been written by the RRO, based on ERO requirements, for consistency. Replacing the RRO with the PC in the standard raises concerns. The responsibility for each PC to develop their own model data requirements may result in

inconsistent data being submitted to the ERO. It is preferrable that the RRO remain in the process. R3 – With each PC developing their own model data requirements, there is concern once again with consistency in the data submitted by the entities under this requirement. R5 – We believe the EROs should be responsible for providing model data requirements as stated in R1. The EROs are responsible for creating the Interconnection models. Therefore, it seems reasonable that the EROs set the model data requirements to facilitate a process that would not create seams issues which could occur with the increase of PCs that would be involved.
Yes
R1.1 – Most state estimators have been developed based on the planning model. Therefore, it should be rare for any discrepancy to occur. It appears that this is more of an operational function to validate the accuracy of the state estimator. The requirement also does not define what data is to be validated. R1.2 – The requirement does not define what data is to be validated. The first sentence should also include “by comparing it to actual system behavior” (as was done in R1.1) to specify how the data is compared. The MOD standards also need to assign responsibilitites and requirements for data validation and data submittal by GOs, particularly for dynamic models. If the generator model is not correct, the planning model will not be correct.
Group
BANC & SMUD
Joe Tarantino
No
Yes
SMUD is submitting a Negative positions for both of the Modeling Data Standards (MOD B). Although we believe the condensing of the MOD-010 thru MOD-015 standards are a movement in the right direction the concerns are such that we feel validate the Negative position. MOD-032-1 –Power System Modeling & Analysis Salient Issues: • For R1 the Planning Coordinator should be replaced with correct wording that allows for a regional process to be implemented. This would allow for a single reporting procedure by multiple PC/PAs to be established among entities providing data consistency necessary for system modeling. • R2 should also be driven by the regional process of R1. The data request hat is required for modeling should come from the PC who is responsible for ensuring accuracy of modeling parameters and should work with the appropriate entities who have that data. This would allow the modeling of data to be populated in the models utilized by the PC/TOP for their system studies. • R4 should be reconstructed such that it requires the PC/PA and the owner of a facility that requires modeling to identify acceptable modeling characteristics for the program utilized by the PC/PA. If the owner submits a unique block diagram that may not directly correlate to the available model in the PC’s program.
Yes
SMUD is submitting a Negative positions for both of the Modeling Data Standards (MOD B). Although we believe the condensing of the MOD-010 thru MOD-015 standards are a movement in the right direction the concerns are such that we feel validate the Negative position. MOD-033-1 –Steady-State & Dynamic System Modeling Validation Salient Issues: • For R1 the overarching steady-state and dynamic validation should be conducted at a regional level for regional modeling validation. o Having individual PC evaluate their own bubble misses the impact that would be identified on large-scale system performance. o Provide for collaboration among multiple industry experts o A 24-month period is too restrictive, suggest a 5-year period. o For R1.3 there is not specific performance requirement identified leaving the measure for “too large” of system performance subjective. • We support a regional modeling validation that requires PC & TP or other appropriate entity to participate in the regional review that would include performance measures in the sub-regions. • Individual PC/PA/TP performance should be limited to steady-state validation. Dynamic validation would be covered under the participation in the regional validation requirements.
Group

ACES Standards Collaborators
Ben Engelby
Yes
(1) We recommend that the drafting team consider revising its approach to MOD B. NERC recently hired industry experts to perform an all-encompassing review of each standard that is currently in effect. According to the report titled “Standards Independent Experts Review Project: An Independent Review by Industry Experts,” there are numerous MOD standards that are recommended to be combined with the TPL standards. The MOD B standards were recommended to be included in a new construct, where requirements would be developed to “assess transmission future needs and develop transmission expansion plans – not operational planning.” We strongly recommend that the drafting team review these recommendations and consider revising the draft SAR to take into account the TPL standards and to remove references to operational planning. This will greatly reduce the compliance burden of maintaining evidence for both TPL and MOD standards. We are unable to support this standard until the team proposes these changes in the SAR or justifies why the recommendations should not be acted upon at this juncture. (2) We are concerned that the informal development process that was originally contemplated has gone off course. The original plan that was announced to industry was to have an informal development team create a proposal for a standard, who would then pass the work to a formal standard drafting team to continue the development process. This is not what has occurred. Instead, the informal development team drafted the initial draft standard prior to the SAR being approved through the formal process. The informal development process should not circumvent the NERC Rules of Procedure. (3) We question the value in posting the draft standard with the SAR. What good is the SAR posting if a standard has already been developed? This gives the impression that the Standards Committee has already determined the need for the standard and eliminates the opportunity for stakeholders to provide comments for consideration. We urge NERC to pay close attention to its Rules of Procedure and the Standard Process Manual to avoid deviations and setting precedent that could be challenged in the future. While we agree in principle with the consolidation of the numerous requirements in this project, the Standards Process Manual still must be followed. (4) We are also concerned that there was a deviation in the standards process manual regarding the selection of the drafting team. The informal team should not have been appointed as the formal standard drafting team without soliciting nominations first, as this creates the perception of NERC hand selecting drafting team members, which is not in accordance with the standards development manual. The nomination period began after the draft standard was posted, which clearly shows the work of the ad hoc team was to develop the draft standard instead of vetting the issues with industry and having a proposal outlined in the SAR. The initial draft standard should be the work of the formal standard drafting team. We doubt that there was sufficient time for any new drafting team members that did not participate in the informal development process to thoroughly review the language in the draft standard. The method of developing the initial draft should comply with the NERC Rules of Procedure in the same manner as all other phases of formal standard development.
No
There was not a field to enter comments for question 2 on the unofficial comment form. Please see our comments in question 3.
(1) We have concerns with Requirement R1. R1 states: “Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for its planning area…” The phrase “in conjunction with each of its Transmission Planners” is not a defined or measureable action. Moreover, the phrase is subjective and does not clearly state which Transmission Planners are applicable to R1. This could also lead to overlap in planning areas and may suggest a shared responsibility among functions. We recommend deleting the phrase “in conjunction with each of its Transmission Planners.” This will make the requirement clearly apply to the PC and avoid the confusion of whether the requirement applies to the TP. (2) Requirement R1, parts 1.1 through 1.6: Why is this criteria included in the requirement and not in an attachment? We recommend adding “where confidentiality agreements allow” for part 1.3. There are several requirements that take this approach, including TOP-002 R3, R4 and R16, to protect confidential information. (3) Requirement R3. We believe this requirement could be the only requirement in the standard. Point to the attachment of the types of data that is required and make the standard a straightforward process. This could still satisfy the FERC directives. (4) Requirement R4. This requirement is overly complicated. The feedback loop does

not need to be a requirement. According to the NERC Compliance Operations guidance document, "the language in the requirement and the purpose of the standard, which is to facilitate the transfer of data for modeling purposes, the auditor will verify that the data was delivered as specified." There is no need to have a feedback loop, only that the data was delivered as specified. Further, this requirement could meet the P81 criteria. We recommend striking R4. (5) In addition, we appreciate the supplemental information provided in this posting. We would like to see compliance guidance on each requirement in future postings, or a draft RSAW to supplement the standard.
No
There was not a field to enter comments for question 4 on the unofficial comment form. Please see our comments for MOD-033-1 in question 5.
(1) We do not believe a standard is needed for validation. We suggest that the drafting team consider other alternatives to approaching the FERC directive instead of developing a validation standard. (2) Requirement R1. We believe it would be helpful to clarify the meaning of the word "validate." Is a Planning Coordinator compliant if it has a modeling program "designed to represent conditions" or must the Planning Coordinator have a program that duplicates or can be made to duplicate actual conditions? The former approach does not punish the Planning Coordinator if the program fails to meet an auditor's view of accurate results. The latter approach may result in Planning Coordinators being required to simulate a state that cannot be duplicated. Also, Part 1.1 seems to imply validate means compare. A PC could compare their model to real-time conditions and determine that there are large differences or small differences. Since no model will ever represent actual conditions perfectly, how small do the differences have to be? We do not advocate that the standard should highlight mandate specific thresholds but highlight this point because it will lead to inconsistent compliance application. Two auditors may look at the same validation data and have different opinions on whether the differences are small enough to consider the model validated. (3) The validation process needs to consider that most of the models that a PC develops are future models and, therefore, should not be validated against real-time system conditions since system topology, load levels and generation patterns can be quite different. Validation should only focus on near-term models. (4) Requirement R1, part 1.1. We would like clarification that entities are not required to own a state estimator to be in compliance with part 1.1 and will not be required to purchase and stand up a state estimator. The language states, "represented by a state estimator case…" We appreciate additional clarification, perhaps in the technical discussion section, that specific alternative sources would be acceptable. (5) We suggest that all references to state estimators should be removed from the standard. Validation should be performed against an appropriate data source. State estimators can certainly be good data sources but care must be taken in using them to validate models because they do not preserve energy balance at a bus as a power flow model does. Since they are a statistical fit of measurements to a transmission model, the errors at each bus can accumulate and lead to larger errors, especially in large interconnection models. Thus, we suggest that the use of state estimators should not be suggested explicitly because real-time measurements may be a better data source. (6) Requirement R2. The measure and requirement are mislabeled. The requirement is labeled as "M2" and the measure is labeled as "R2." (7) Requirement R2. We would like the drafting team to provide a rationale why it chose 30 days for an appropriate timeline. There is no technical justification listed. (8) Requirement R2. This requirement is subject to Paragraph 81 criteria because it relates to reporting obligations to other responsible entities. The P81 criteria states, "B4. Reporting: The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact." Furthermore, the RC should be more than willing to provide the necessary data to ensure models are validated. The RC often inherits these models for use in operational planning. (9) Thank you for the opportunity to comment.
Individual
Clay Young
SCE&G
No

No
R1 We have concerns regarding replacement of the RRO with the PC in the standard. In addition, with the learning curve time associated with testing and forwarding to those finalizing models the opportunities with seams issues seem significant and possibly on-going with the increase of PCs involved. Therefore, it would preferable to maintain the Region in the process as at present. R2. It appears that without a uniform data standard the scope of the data may not be uniformed. Using the Region as a collection point has merit in ensuring that the data requirements are consistent. R3. The concern centers on consistent and comparable data submitted. Removing the Regions as the collectors may necessitate development of a guideline manual that all accept to ensure that data is consistent. R5. The SDT is requested to include clarification language that the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection models, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection models, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection models and each will provide a procedural manual for their area to ensure data submittal is consistent.
Yes
The SDT is requested to review the other MOD standards to ensure that GOs are covered and required to submit data when requested.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
Section 4.1, Applicability - The Functional Entities should be listed in a non-plural form for consistency with other NERC standards.
Yes
R1. / R5. There is insufficient linkage between R1 and R5 for the Eastern Interconnection. Within the Eastern Interconnection, there are fifty (50) registered Planning Authorities (based on 8/27/2013 NERC Compliance Registry Matrix). While the standard is written in a way that will allow established multi-regional (ERAG) model development processes for steady-state and dynamics models to continue, it fails to capture the common framework and sequence that must be established at the Eastern Interconnection level for coordinated Interconnection-wide model development to occur. The “ERO or its designee” (currently ERAG for the Eastern Interconnection) should be the organization that establishes modeling data requirements and reporting procedures for the Eastern Interconnection level models. This is implied in R5, but not explicitly addressed in R1. Each PC may develop as many models as it deems necessary for its own area; however the Interconnection-wide models should be a minimum set of models that all of the PCs in the Eastern Interconnection develop under a common set of guidelines and assumptions that are established by the “ERO or its designee”, in conjunction with PCs within the Interconnection. A key word used in the purpose of the standard is “consistent”. It is unreasonable to assume that fifty diverse PCs will independently develop modeling requirements and reporting procedures that will roll up into a consistent end product without some form of collective governance. The drafting team should consider developing a separate standard for each Interconnection (reference IRO-006 as precedent) in recognition of the current modeling practices employed in each Interconnection. While a “one size fits all” standard is understandably desired, it perhaps leaves too much ambiguity. R2. The Transmission Planner should be added to the list of functional entities that can request data requirements and reporting procedures from the Planning Coordinator. The rationale statement for R2 recognizes that changes in ownership can occur. If ownership of transmission assets changes, the Transmission Planner for those assets may also change. The “new” Transmission Planner for those assets may not have worked in conjunction with the Planning Coordinator to develop the data requirements and reporting procedures under R1.
Yes

Benchmarking planning models to real time snapshots can be an exercise in futility based on the large number of variables in the models (loads, topology, gen. dispatch, interchange, etc.) and the limited access to real time data from neighboring areas that can be translated into the planning model for a selected snapshot. An alternative approach would be for the RC and TOP to benchmark operations planning models to real time state estimator snapshots, and have the RC and TOP work with their associated PC and TP to address any particular model concerns identified.
Individual
Christina Conway
Oncor Electric Delivery Company LLC
No
No
R1. Oncor Electric Delivery supports the idea of combining the respective data submittal standards into a single data submittal standard. However, Oncor believes a shared approach between the Planning Coordinator and Transmission Planners to determine data requirements would be more thorough and beneficial to all parties. Oncor supports the verbiage indicating that the Planning Coordinator is to determine modeling requirements “in conjunction with each of its Transmission Planners. ” However, Oncor is concerned that this verbiage is insufficient to address the Transmission Planner’s concern that a Planning Coordinator may dictate data requirements without consulting those whom deal with the data for their particular portion of the grid. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator’s unilateral determination of requirements to be imposed upon various entities. Furthermore, the verbiage in requirement R2 stating the “Planning Coordinator shall provide its data requirements…” raises concerns that the Planning Coordinator may act without consulting the Transmission Planners. Oncor recommends inserting language indicating that the data requirements be developed together between the Planning Coordinator and the Transmission Planners. R1.1 Based upon the comments provided for Requirement R1, above, Oncor Electric Delivery believes that the Attachment 1 table is too prescriptive and needs to be modified to display those data requirements agreed upon by the Planning Coordinator and the respective Transmission Planners. R4. Oncor Electric Delivery recognizes that data may need to be updated in a timely manner so that the changes can be accurately modeled; however, the 30 calendar days response period may not be sufficient. If the Planning Coordinator is not agreeable to a longer response period, the responding entity may be found in non-compliance with this requirement. The response time should be mutually agreed to between the parties, and should not be dictated by the standard.
Yes
N/A
Individual
John Brockhan
CenterPoint Energy Houston Electric, LLC
No
No
CenterPoint Energy appreciates the efforts of the SDT and agrees with the approach of consolidating existing MOD standards 011 through 015 into one standard. Our specific concers are detailed below: R1. CenterPoint Energy supports a collaborative approach between the Planning Coordinator and Transmission Planners to determine data requirements and appreciates the SDT’s attempt to incorporate this approach by indicating that the Planning Coordinator is to determine modeling requirements “in conjunction with each of its Transmission Planners. ” However, CenterPoint Energy is concerned that this verbiage is insufficient to address the concern that a Planning Coordinator may

unilaterally dictate data requirements. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator's unilateral determination of requirements to be imposed upon various entities. Furthermore, some entities affected by the requirements, such as transmission and generation owners, would not have an opportunity to be represented in an open and transparent stakeholder process to weigh the relative merits against the feasibility, cost, and burden of proposed new requirements. In addition, the language in R2 stating the "Planning Coordinator shall provide its data requirements…" raises the concern that the Planning Coordinator may act alone. As an alternative, CenterPoint Energy recommends inserting "mutually agreeable" as follows: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop mutually agreeable steady-state, dynamics, and short circuit modeling data requirements… R1.1 CenterPoint Energy believes that the Attachment 1 table is too prescriptive and needs to be modified to retain the high level numbered items for steady-state and short circuit data and to remove the details identified by the lowercase letters. CenterPoint Energy also believes that the Dynamics data requirement No. 5 "Demand" data requirement is vague and needs to be clarified. Making these modifications will provide the consistency for which the SDT is striving but will relieve the unnecessary compliance burden of the current draft. R4. CenterPoint Energy recognizes that data may need to be updated in a timely manner so that the changes can be accurately modeled; however, the 30 calendar days response period may not be sufficient. If the Planning Coordinator is not agreeable to a longer response period, the responding entity may be found in non-compliance with this requirement. The response time should be mutually agreed to between the parties, and should not be dictated by the standard.
Yes
Individual
Texas Reliability Entity, Inc.
Texas Reliability Entity, Inc.
No
Yes
Yes
1) TRE believes that each Planning Coordinator, in conjunction with each of its Transmission Planners, must implement a documented process to validate the data used for steady state, short circuit, and dynamic analyses for its planning area against actual system responses, and once errors are identified during the validation process, the errors need to be corrected within 60 calendar days. a. TRE believes MOD-33-1 should be changed to include Short Circuit Model validation in order to ensure the necessary accuracy is achieved in all models included in MOD-32-1. b. Since the validation process in MOD-33-1 includes comparing models built by Transmission Planners to actual system behavior, TRE believes MOD-33-1 should be changed to also apply to Transmission Planners. c. TRE believes that the errors identified during the validation process need to be corrected within a specific amount of time to ensure corrections are timely, so TRE believes MOD-33-1 should be changed to include the requirement to make corrections within 60 calendar days.
Individual
Ed O'Brien
MIodesto Irrigation District
No
No

MOD-032: 1. In MOD-032, there is a blurring of responsibilities between the Transmission Planner and the Planning Authority (i.e., Planning Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific model data required (R1.1) is apparently detailed in Attachment 1, which does not seem to exist.
MOD-032: 1. In MOD-032, there is a blurring of responsibilities between the Transmission Planner and the Planning Authority (i.e., Planning Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific model data required (R1.1) is apparently detailed in Attachment 1, which does not seem to exist.
No
MOD-033: 1. In MOD-033, there is a blurring of responsibilities between the Transmission Operator and the Planning Authority (Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific requirement (R1.1) for use of a State Estimator or equivalent, is not practical, as many smaller utilities cannot afford one nor justify the need for one in their normal day-to-day operations. 3. The specific requirement (R1) that the Planning Coordinator (Authority) "validate model data used for steady state and dynamic analyses for its planning area against actual system response" is not always possible, as the local planning area simulated response is not only dependent on the accuracy of the local planning area equipment models, but also on the accuracy of the adjacent planning areas equipment models, too.
MOD-033: 1. In MOD-033, there is a blurring of responsibilities between the Transmission Operator and the Planning Authority (Coordinator). As MID has no officially designated Planning Authority (Coordinator), this could be a problem. There are also other utilities in this same situation. 2. The specific requirement (R1.1) for use of a State Estimator or equivalent, is not practical, as many smaller utilities cannot afford one nor justify the need for one in their normal day-to-day operations. 3. The specific requirement (R1) that the Planning Coordinator (Authority) "validate model data used for steady state and dynamic analyses for its planning area against actual system response" is not always possible, as the local planning area simulated response is not only dependent on the accuracy of the local planning area equipment models, but also on the accuracy of the adjacent planning areas equipment models, too.
Group
MRO NERC Standards Review Forum (NSRF)
Russel Mountjoy
Yes
This process appears to be out of synch. Approving a standard without approving the SAR first. The informal process seems to be rushing the process without due diligence.
No
Requirements 1 from both MOD-014 and MOD-015 have not been mapped to the new proposed standard. Developing power flow and dynamic models are needed to preform the needed studies for FAC, PRC, and TPL standards. This is a gap in the MOD standards. This is gap is which entity is developing models? There needs to be a standard directing an entity to develop models or a change in the ‘Rules and Procedures’. Specific comments/questions below: • Has ERAG acknowledged that they will be getting 51 raw data sets from the PCs (i.e. unsolved, incomplete data)? • ERAG is not in the functional model and not subject to compliance, can the PC’s be responsible for modeling issues? • The PC is really just a middle-man for the data, so why even be in the process? What value is there? • If one or more regions gest out of building models, is ERAG still the one to aggregate them? • If ERAG is the regions and they build the power flows is there still a conflict of interest? MAPP as a PC has not been involved with the model development or data collection. We do not have the infrastructure to develop models; We need a long implementation time to put these facilities in place. Not everyone uses the PTI product ‘model on demand’, as the tool the TO could use on behalf of the PC. The first suggestion is a modification to the R1.5 text “R1.5. Specification of the case types or scenarios to be modeled (for steady state and dynamic data sets); and…”. The second suggestion is a modification to the R2 text, replace “…in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures.” with “…in it s planning area within 30 calendar

days of any data requirements and reporting procedure modifications.”. R2. Each Planning Coordinator shall provide its data requirements and reporting procedures developed under Requirement R1 to any Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider in its planning area within 30 calendar days of a written request for the data requirements and reporting procedures. Issue: Requirement 2 above is based on a “written request” for data requirements and reporting procedure while the comment states this would be expanded to modifications to data requirements and reporting procedure. We interpret this to mean that whenever there is a “modifications” to data requirements and reporting procedure, the entity will be required to resend this information to each requestor within 30 days. Recommend the term “modifications” be removed.
We request clarification of item 4 of the Steady-State portion of Attachment 1 in MOD-032-1: 4. AC Transmission Line or Circuit (series capacitors and reactors shall be explicitly modeled as individual line segments) [TO] Why does the drafting team see the need to explicitly model series capacitors and reactors? This equipment is usually not breakered and thus from a contingency standpoint, is part of the line that it’s connected to. Explicitly modeling series reactors and capacitors would provide misleading results when performing N-1 contingency analysis. The SAR goes to great length to describe a purported problem with gaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement In an apparent attempt to avoid the need for a technical justification, the SAR states: “(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection.” The Planning Horizon is strewn with similar unknowns that we cannot know (load models, generator dispatch, transmission construction), and this statement alone is not technical justification. However, accurate models may be needed for the Operating Horizon. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. The terms of the Confidentiality Agreement (CA) are important to consider. These models are to be shared with all the planners within an Interconnection. The SAR on page 5 states: “(p)roprietary models with details hidden from the user (‘black box’ models) or those models that cannot be shared across the Interconnection are not acceptable.” How will the terms of such a CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR’s claim that: “The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary”, and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the vendor did not cooperate in renegotiating those . This challenge also exists in existing approved standards, IRO-010 (currently mandatory) and TOP-003-2 (approved by BOT, awaiting FERC decision). If the RC or TOP make a request for that model in their data specifications, then the GOP (or other entity) must submit those models to the RC and TOP. The SDT ought to address the question, is there a Reliability Related need to ensure that proprietary models gathered at the TOP or RC level be shared across the interconnection. In the Planning Horizon, there is too much inaccuracy in other variables that the effect of the lack of proprietary models cannot be separated from the influence of those other variables; hence, the question ought to be answered from an Operating Horizon perspective. Does the lack of these proprietary models cause a benchmark of Operating Models to actual events to be unacceptably innacurate?
No
How are the PC’s going to validate data, by range checking or in a power flow? With EMS data? Is

there an EMS case that works in PSSE? Many Models are built for non-coincident peak time frames, there would be many issues trying to validate for a real-time event. The PC is not a real time entity; we would be validating the RC models (RC required to provide data to PC), seems the wrong entity is doing the validation. The PC has no obligation to verify data once it leaves its hands (i.e. sent to the ERO designee). The wrong model is being validated. By definition, Planning Horizon models cannot be accurate due to forecast error; hence, Operating Horizon models should be validated by the RC rather than Planning Horizon models being validated by the PC. After all, in order to validate a Planning Horizon model to a past event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an Operating Horizon model as a first step The proposed standard has overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis The models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator Please separate the Standards into separate ballots.
Individual
Alice Ireland
Xcel Energy
No
Yes
Would like to ensure that the PC's are required to work closely with their members to resolve modeling and modeling data issues. Please consider modifying R2 to require the PC to be responsive similar in concept to what is required in FAC-010-2.1 R5 (except related to model building vs. SOL Methodology). FAC-010-2.1 R5. If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason.
Yes
Concerned that state estimator case or other Real-time data may not contain enough level of detail required to validate the case (e.g. impacts of the low voltage facilities (generators, loads) on the BES).
Individual
Jose H Escamilla
CPS Energy
No
Yes
CPS Energy's specific concerns are detailed below: R1. CPS Energy supports a collaborative approach between the Planning Coordinator and Transmission Planners to determine data requirements and appreciates the SDT's attempt to incorporate this approach by indicating that the Planning Coordinator is to determine modeling requirements "in conjunction with each of its Transmission Planners." However, CPS Energy is concerned that this verbiage is insufficient to address the concern that a Planning Coordinator may unilaterally dictate data requirements. In addition, the language in R2 states that the "Planning Coordinator shall provide its data requirements…" raises the concern that the Planning Coordinator may act alone. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator's unilateral determination of requirements to be imposed upon various entities. Furthermore, some entities affected by the requirements, such as transmission

and generation owners, would not have an opportunity to be represented in an open and transparent stakeholder process to weigh the relative merits against the feasibility, cost, and burden of proposed new requirements. As an alternative, CPS Energy recommends inserting "mutually agreeable" as follows: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop mutually agreeable steady-state, dynamics, and short circuit modeling data requirements… R1.1 CPS Energy believes that the Attachment 1 table is overly prescriptive. Our main concern is in retaining evidence that each particular item has been submitted to the appropriate parties. This is a large amount of documentation to retain to indicate that each item has changed or has not been changed. At a minimum, the table in Attachment 1 needs to be modified to retain the high level numbered items for steady-state and short circuit data and to remove the details identified by the lowercase letters, otherwise, this table should be removed. CPS Energy also believes specific reference to a composite load model should be removed from the Dynamics data requirement No. 5 "Demand". While we find the composite load model very important in dynamic analysis, we believe the load modeling requirements should be determined at the regional level. Therefore, the table should read as follows: 5. Demand [LSE] (consistent with system load representation and components as a function of frequency and voltage). Making these modifications will provide the consistency for which the SDT is striving but will relieve the unnecessary compliance burden of the current draft. R2. This requirement makes no mention that the Transmission Planner is a recipient of the data requirements, even though they helped in creating them. R4.2 This requirement should be removed as it is redundant to what is required in R3 and R4.1. Also, this requirement strays from data collection and leans toward data validation. M4. In general, this measurement is overly prescriptive and is excessive and cumbersome from a documentation standpoint. The documentation methodology should be determined at a regional level, as requests for new data in one region may be extremely different than in other regions.
Yes
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
No
Austin Energy (AE) appreciates the efforts of the SDT and agrees with the approach of consolidating existing MOD-011 through MOD-015 into one standard. Our specific concerns are detailed below: (1) For Requirement R1, AE supports a collaborative approach between the Planning Coordinator and Transmission Planners to determine data requirements and appreciates the SDT's attempt to incorporate this approach by indicating that the Planning Coordinator is to determine modeling requirements "in conjunction with each of its Transmission Planners." However, AE is concerned that this language does not address the concern that a Planning Coordinator may unilaterally dictate data requirements. MOD-032 does not define a governance structure and appeals process for the Planning Coordinator's unilateral determination of requirements imposed on various entities. Furthermore, some entities affected by the requirements, such as Transmission and Generation Owners, would not have an opportunity to be represented in an open and transparent stakeholder process to weigh the relative merits against the feasibility, cost, and burden of proposed new requirements. In addition, the language in R2 stating the "Planning Coordinator shall provide its data requirements …" raises the concern that the Planning Coordinator may act alone. As an alternative, AE recommends inserting "mutually agreeable" as follows: "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall develop mutually agreeable steady-state, dynamics, and short circuit modeling data requirements …" (2) For Requirement R1.1, AE believes the Attachment 1 table is too prescriptive and should be modified to retain the high level numbered items for steady-state and short circuit data and to remove the details identified by the lowercase letters. AE also believes the Dynamics data requirement No. 5 "Demand" data requirement is vague and should be clarified. Making these modifications will provide the consistency for which the SDT is striving but will relieve

the unnecessary compliance burden of the current draft. (3) For Requirement R4, AE recognizes that data may need to be updated in a timely manner so the changes can be accurately modeled; however, the 30 calendar days response period may not be sufficient. If the Planning Coordinator is not agreeable to a longer response period, the responding entity may be found in non-compliance with this requirement. The response time should be mutually agreed upon by the parties and should not be dictated by the standard.
No
AE believes that a requirement to validate dynamic models at least once every 24 calendar months uses an inappropriate timeframe. AE suggests that Requirement R1, Part 1.2 be changed to "Validate its portion of the system in the dynamic models at least once every 60 calendar months through simulation of a dynamic local event. Complete the simulation within 12 calendar months of the local event."
Individual
Richard Vine
California Independent System Operator
No
Yes
For this Standard to work effectively, it is essential for the PC to know all registered entities (TOs, GOs, TPs, DPs, LSEs, TSPs, RPs) within its purview, and vice versa (entities need to know who their PC is.) It would be helpful if NERC or the Regional Entity would provide such a mapping (listing of registered entities (TO, GO, TP, DP, LSE, TSP, RP) within their purview) to the PCs on an ongoing basis so that PCs and data submitting entities can stay current on their obligations.
Yes
It would be helpful to clarify the meaning of the word "validation". Is a PC compliant if it has a program "designed to represent conditions" or is the PC expected to have a program that duplicates or can be made to duplicate actual conditions? The former approach does not penalize the PC if the program does not meet an Auditor's view of accurate results. The latter approach may result in PCs being required to simulate a state that cannot be duplicated.
Group
Southern Company: Southern CompanyServices, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
No
Yes
On R1: Uniformity of the data request form is desirable. R1 data requirements should be sensitive to the life cycle of the generator (age, data availability for pre-1970 units, units in various stages of project development, planning, and start up), or to unconventional data requests that would require reverse/extensive engineering techniques to fulfill. R2 is purely administrative and should be eliminated. The PC should simply deliver the data requirements and reporting procedures to the BAs, GOs, TOs. etc. once they have developed or revised them. Attachment 1 should provide additional details of precisely what "minimum" data is required - for example, on the generator which time constants and which reactances are required. For the VSL on R3, perfect data submission is in violation (0% missing/unformatted/late is less than 25%) - please correct. Consider some minimum level of data shortage/formatting/tardiness being acceptable rather than instituting a "zero tolerance"

position - say 5% up to 25% is the Lower VSL. A zero tolerance for a VSL seems inconsistent with the NERC Reliability Assurance Initiative and risk based compliance and enforcement approach. For R4.2 - an explanation with a technical basis for maintaining the current data should be allowed here too (like R4.1). Attachment 1, steady state, item 3c - station service auxiliary load data should be restricted to normal plant configuration for the GO Attachment 1, steady state, item 3d - please define what is meant by "regulated bus". Attachment 1, steady state, item 3e - is this the voltage schedule? Attachment 1, steady state, item 3f - what value is the % ownership to the model? Attachment 1, steady state, item 3h - please clarify what this means for generating units. Attachment 1, steady state, item 6g - please explain what this rating is. Attachment 1, steady state, item 9 - we believe that there should be a requirement for the PC to provide technically based reasons for expanding the data request beyond what is listed in Attachment #1. (Requirement 1, Attachment 1 - steady state, item 9). We recommend R5 be removed from the draft standard altogether and that the PC deliver the data in response to a NERC Rules of Procedure Section 1600 data request. This requirement is purely administrative.
Group
FirstEnergy
Doug Hohlbaugh
Yes
FirstEnergy (FE) recommends that the new TPL standard (TPL-001-2; now TPL-001-4) be reflected under the related standards section of the SAR. The drafting team should consider the need/benefit of having the proposed MOD-032-1 standard include modeling requirements listed in Requirement R1 of the new TPL standard. It’s FE’s understanding that the new TPL standard envisioned having the modeling requirements reflected in Requirement R1 removed from the TPL standard when the MOD standards were updated. At a minimum, references to existing MOD standards will require revision in the TPL standard if R1 in the TPL standard is retained.
Yes
See response to Question 3
Fundamentally, FE supports the approach taken in the proposed MOD-032-1 to remove the "fill-in-the-blank" aspect of the standards and to remove the Regional Entity as being integral to the modeling building effort. However, FE has some concerns in the details as proposed in this draft. The following outlines our primary concerns. Additionally, our comments raise questions that we would like addressed by the drafting team. Requirement 1 – As written, this requirement may provide too much flexibility for the Planning Coordinator (PC) to specify “the level of detail to which equipment shall be modeled” (R1, Part 1.4). For instance what if one PC requires a bus/branch model while another prefers more detail and obligates a node/breaker model? While drafting teams must strike an appropriate balance in describing “what” is required and avoid specifics on “how” to accomplish an industry obligation, sometime more detail may be appropriate to drive consistency; particularly in a given Interconnection. The Rationale box for R1 which states that “It would likely be most efficient for PCs to fashion their data requirements and reporting procedures with the interconnection-wide common format in mind” supports our concern. More on R1, Part 1.4: It is our interpretation that the level of detail and model requirements, including system topology, handling of conductor changes along a transmission line, etc may be different each model type. For instance, the details of a steady-state model may differ compared to a short-circuit model. Is FE's understanding correct? R1, Part 1.2 – It is important that the specified data format established by a PC be publically available and not unique to any particular vendor software application. Requirement 2 - The PC should be required to provide any BA, GO, LSE, etc, their initial data requirements and thereafter whenever any change is made. The need for a PC to retain compliance evidence that it provided its requirements within 30 days upon request is an unnecessary administrative compliance burden that does not support reliability. In reality, a PC will likely make available its requirements through a website, but they should still be required to communicate changes to affected parties. Requirement 5 - Requires that PCs submit data to the ERO (or designee) for interconnection-wide models. As stated above, FE is concerned about the diversity of data formats, details, etc that PCs will establish. The existing MOD standards have the Regional Entities (or RROs) drive the model requirements so the opportunity for

differences is much lower that what may occur in the proposed standard. In the Eastern Interconnect, there are 51 PCs within 6 regions. This may create widely varying model data requirements and reporting procedures. We suggest that within the Eastern Interconnect the ERAG, rather than the PC, be designated to drive consistent model building requirements and practices to develop power flows, short circuit and dynamic base case models. The standard then would assess functional entities adherence to the established ERAG practices.
No
See response to Question 5
We support the validation effort, however, it should be limited to near-term (year one) models since longer term models may differ greatly in modeling assumptions such as load, generation dispatch and interchange flows.
Group
Bonneville Power Administration
Jamison Dye
Yes
BPA has concerns with the requirement to provide short circuit data (zero-sequence information) in powerflow base cases. Currently this data is not part of the submittal required by WECC in the basecase model representation...nor is it required to be included by the WECC DPM (data preparation manual). The protection groups obtain this information from Aspen One-Liner (the data exists and is maintained in a separate database). This new requirement creates a redundancy and increased workload without increased reliability. BPA recommends that the drafting team consider addressing this disparity.
BPA believes that the requirement to include short-circuit data demonstrates that different databases are being used to accomplish the planning and operation/protection of the power system and that the detail of the models are specific to address the underlying need. For example, wind models at the planning level are equivalent to a single generator, step-up transformer, collector system, and the interconnection transformation to the BES (bulk electric system) while the individual turbine units are modeled with all of their intricacies for protection purposes.
No
BPA has concerns about validating operational models with planning models, specifically in ensuring the alignment between state-estimator models and planning representations of the power system. BPA believes that there are significantly different degrees of modeling detail required by each and a history of the needs/purposes for the two models not being the same. BPA recommends the drafting team consider addressing this concern.
BPA believes that the alignment between the state-estimator and planning representations of the power system is challenging. The detailed representation of a breaker/node model vs. the bus/branch approach utilized by most powerflow programs have presented obstacles that ended up in a stalemate between operations and planning. For example, a substation with a ring bus topology can contain significantly more data points than the single bus number it is assigned in a powerflow model. BPA recommends that the drafting team remove the requirement to align state estimator and planning representations to eliminate this challenge.
Group
Western Area Power Administration
Lloyd A. Linke
Yes
No
The proposed MOD-032 replaces MOD-010 through MOD-015. In the fill in the blank standards, MOD-014 and MOD-015, the RRO had the responsibility to build the interconnection specific models. The

proposed MOD-032 standard states that each PC must submit the data to the ERO or its designee to support the creation of the interconnection specific models. There is some concern that this inclusion of the PC in the data collection process and the elimination of the RRO in building the interconnection model may create issues in building the interconnection specific models. In the Eastern Interconnection, it would go from 6 RRO regions gathering and coordinating regional data to raw data sets from the 51 individual PCs possibly. ERAG in the EI has discussed this and believes a solution can be developed but acknowledges a change in the existing process needs to be made. Some uncertainty to what this new process looks like. Also, it may be that the PC has not been involved with the model development or data collection which means that some PCs may not have the infrastructure to even collect data.
No
The proposed MOD-033 drafts a new validation process that requires the PC to validate the data collected in the MOD-032 process for both steady state and dynamic analyses against actual system responses. Data/conditions collected for a planning horizon must be validate against actual system behavior represented by a state estimator case or other Real-time data sources. Typically planning models are built for non-coincident peak time frames for a worst case scenario in the planning horizon which makes it difficult to validate against a real-time event. Also, a PC is an entity not typically involved in real time processes. They would be requesting data from an RC or TOP in an operating horizon and benchmarking a model they did not create against the data received from a real time entity. I would also assume they would have to validate which model is providing valid information or results. It seems a difficult task to bench mark these two model sets especially when the PC has only the responsibility to collect the data and no obligation to build models in the planning horizon and does not typically have access or functional responsibility in the development of the real time system data. I believe there could also be confidentiality concerns for a RC and TOP with being directed to provide any PC actual system behavior data.
Group
Colorado Springs Utilities
Kaleb Brimhall
No
Yes
We agree with consolidation and simplification.
MOD-032-1 does not apply well to the way that WECC is structured. Planning Coordinators vary widely in size and scope across the WECC footprint. (Also, some entities within WECC are not registered as PCs, and yet are not under the jurisdiction of another PC.) Making PCs responsible for the development of modeling data requirements for each of their respective areas invites the possibility of issues with data compatibility across the interconnection, and is inefficient and duplicates effort. A WECC variance would probably need to be written into the standard to preserve the existing process that relies on a WECC Data Preparation Manual to define the technical model data requirements and reporting procedures for the interconnection. Need more detailed explanation of expectations for validation accuracy. How many and which models need to be validated as a part of the documented process?
No
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