Individual or group. (44 Responses)
Name (30 Responses)
Organization (30 Responses)
Group Name (14 Responses)
Question 1 (43 Responses)
Question 1 Comments (44 Responses)
Question 2 (36 Responses)
Question 2 Comments (44 Responses)
Question 3 (0 Responses)
Question 3 Comments (44 Responses)

Group
SERC Planning Standards Subcommittee
Yes
Yes
R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are not required in the current version 0 standards. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group
Progress Energy
First, Progress Energy ("PE") notes that many changes to the Requirements language have been appropriate or have improved upon the language of the previous drafts, and PE commends the SDT in this. PE does have concerns, however, with the language in R8 and its corresponding Measure M8, and therefore must select 'no' for Q1 and provide comments. PE disagrees with the language of R8 primarily to the extent that the use of the verb “distribute” with respect to communicating Planning Assessments leads the reader to M8, which lacks language that would provide for the optimal correlation with R8. Regarding the M8 language, PE feels that the term “demonstration of a public posting” is a valid action in demonstrating compliance with R8 and thus should be more clearly described as one of several acceptable methods of distributing Planning Assessments. In addition, given the appropriate concern that NERC and FERC have recently raised regarding Cyber threats and the need for additional Cyber Security measures, PE feels that the public posting language should contain a qualification regarding the security of CEII information. PE thus recommends that an appropriate phrase to use would be “demonstration of a secure public posting”, thereby making clear that a public posting would not be a website accessible to just anyone due to CEII concerns.
Yes
Group
Northeast Power Coordinating Council
No
The wording of Part 1.1.2, “known outages...with a duration of at least 6 months” should be revised to “...at least 1 year”. Also for consideration is that “known outages...with a duration of at least 6 months” are dealt with in operational studies rather than planning studies. Any adverse impacts that these outages might have are mitigated by operational decisions rather than planning decisions within a 6 month horizon. Moving this requirement out of the TPL Standard to an operational standard should be considered. Make the wording consistent between 2.1 and 2.2 as it relates to qualified past studies. Specifically: Parts 2.1.2, 2.1.4, 2.1.5 The language of requirements 2.1.4 and 2.4.3 allowing the performance of one or more sensitivities appears to be inconsistent with language in 2.7.2. 2.7.2

requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. Will varying only one measurable quantity several times in multiple simulations satisfy multiple sensitivity studies or just one sensitivity study? The numbers and types of required sensitivity studies is unclear, and subject to interpretation by PCs and TPs. The current wording in Part 2.1.5, "spare strategy", appears to be open-ended regarding the number of permutations to be analyzed. It should be restricted to assessing only one piece of equipment being unavailable or outaged at a time. 2.1.5 should be consistent with R2 and 2.1 regarding the use of the terms assessment and studies. As with the preceding comment regarding Part 1.1.2, moving this requirement out of the TPL Standard and to an operational standard should be considered. It is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service before the application of category P0, P1 and P2 events. This last sentence states: "…with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." The wording in Part 2.2 "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with the similar statement in Part 2.1: "be supported by current annual studies or qualified past studies". Part 2.7.1 lists potential system actions to address System deficiencies. It is suggested that this list be moved to a guideline or white paper. The wording in Part 8.1 needs to be amended to restrict comments to the most recent assessment only. Contingencies on back to back HVDC installations are not mentioned in the standard. The treatment of combined cycle facilities (all units in outage?) needs to be clarified, as well as Footnote 7 of Table 1 requiring clarification. In Table 1, Event 1 of Category P2 and related Footnote 7 are not clear because of the use of the word "possibly". If the intension is to simulate the line end opening condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote). From Table 1b: "Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0." Firm Transmission Services Loss is also acceptable and should be added (particularly in P1 loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability).
Individual
John Bussman
Associated Electric Cooperative Inc
No
R2.4.1: The SDT has put a stronger emphasis on dynamic load behavior in stability studies (FIDVR, induction motor loads, etc) to be included in the peak models. The standard does indicate that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." We feel that this should be clarified to ensure that the current modeling processes address what NERC desires with this requirement. At a minimum, we recommend that a grace period be implemented to account for any regional modeling practices which need time to implement dynamic load behavior per the draft standard. R2.5: It is our understanding that the Long-Term Transmission Planning Horizon does not require the sensitivity analysis which is required in R2.4 for the Near-Term Transmission Planning Horizon for the stability portion of the studies. R2.7: It is our understanding that Corrective Action Plan(s) do not need to be developed for performance violations observed in the sensitivity analysis (steady state and stability) unless the violation is observed in several sensitivities as it is indicated in R2.7.2: "Include actions to resolve performance deficiencies indentified in multiple sensitivity studies or provide rationale for why actions were not necessary". We feel that this needs to be further clarified. R3.3.1: This requirement indicates that steady state analysis should include the effect of ride-through voltage limitations of generating units. We are having difficulty seeing how this is a steady-state issue. Generally one would expect a generator to experience ride-through voltage issues during faults. Per Table 1, P1.1 already require generator outages be taken – wouldn't that cover this issue? We feel that this needs to be further clarified. R3.4.1: This requirement states that "Transmission Planners shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list". We feel that the coordination requirement should be removed from the standard as this will result in a massive increase in workload/time required to perform the TPL studies. AECI has several ties to adjacent Transmission Planners and Planning Coordinators – it will be a very time intensive task to coordinate with all of these parties. If the standard wants to ensure that the Contingencies overlap – we can agree to that, however we feel

that the SDT needs to give some firm clarity on how far to go with it (how many buses away, only include ties, etc?). R4.1.2: We would like clarification on what is mean by “apparent impedance swings”. R4.3.1: Is the intent of the SDT to require that generic or actual relay models be added to the stability models? We feel that this needs to be further clarified. R8: This requirement states that the Planning Assessments shall be distributed within 90 days of their completion to adjacent Planning Coordinators, Transmission Planners, and functional entities that have a reliability need (3rd Interconnection Customers?). We do not agree with the mandatory requirement of distributing the results of our TPL studies: We consider this information to be CEII We can agree to distribute the results upon request, but do not agree with the 30 day timeframe as more time will be needed to sign applicable Non-Disclosure Agreements, etc.
Individual
Thad Ness
American Electric Power
Yes
Yes
Individual
Greg Rowland
Duke Energy
Yes
Yes
Group
SPP Reliability Standards Development Team
Yes
Yes
A5 It would seem that 84 months wouldn’t be universally attainable due to different system configurations, terrain, geography, and permitting issues that are required to complete a corrective action plan. In 2.4.1 we would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the answer is a very detailed representation of the load system then it may take a longer time to implement. In section 2.7 we would to see clarification on the sensitivity analysis. Is this in reference to seasonal models and differences in fuel availability? We need more detail on how this is to be done so that it won’t be left up to interpretation. We would like for clarification of the planning assessment and who is performing which tasks. We would also like to utilize a regional assessment due to limited resources. Under which criteria should the assessment fall under the regional entity or the individual companies? In section 3.4.1 this type of coordination could be difficult due to other adjacent entities on different schedules and some possibly couldn’t have the amount of detail to incorporate into another’s processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? PC’s between regions are already coordinating for long term studies. Should this standard fall more on the back of the PC’s rather than the TP Can we get a bright line definition of what apparent impedance swings means? R4.3.1 will the detailed amount of data then be incorporated back into the NERC modeling processes and create a more detailed model with better accuracy? R8 We do not agree that we should provide the assessment to every adjacent

PC and TP. We do agree however that if requested by these entities we would provide the assessment. We don’t mind sharing information with requestors but would like a longer duration than 30 days due to the fact that we would like to know what type of “reliability need” any entity would have considering that some of the information could be considered CEII. Non disclosure agreements may be needed in order to provide this information.
Individual
Bernie Pasternack
Transmission Strategies, LLC
Yes
Yes
The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace.
Group
Arizona Public Service Company
Yes
No
With regards to R2, it appears that the VRF has changed from Medium to High without any justification; and with the time horizon of long term planning, AZPS believes there is no justification for changing it from Medium to High.
AZPS would like to reiterate its “Affirmative” voting recommendation with regard to the proposed revisions to the Standard. AZPS erroneously entered a “Negative” Standard vote for one of its voting segments.
Individual
Joe O'Brien
NIPSCO
Yes
Yes
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. This is a little confusing to me. Does this mean the outage must last at least six months? Or does this mean at least model outages that last six months or more. If it is the latter then, I'm not sure that is stringent enough. There may be known critical outages occurring over peak that do not last 6 months. If non-consequential load loss is not allowed for loss of one element, then what about the next contingency? Couldn't that result in having to interrupt Firm service? Is that okay as a corrective action plan in the outage coordination horizon? Does this apply to both near-term and long-term planning? If so, we probably need to model additional unplanned potential outages on top of n-1 conditions. Lastly. in section 2.1.4 should there be a category for high/low wind conditions?
Individual
Scott Bos
Muscatine Power and Water
Yes
No
MP&W would like to recommend that the VRF for Requirement 8 remain “Low”, rather than “Medium.” It is our belief that there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment

comments is not provided within 90 days of a request. This is more administrative in nature. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. Additionally, entities with a reliability-related need for Planning Assessment information generally have the ability to perform their own independent planning assessment of adjacent systems or other areas of interest.
MP&W recommends that the term “System” be replaced with “BES” in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems. This is the current definition of the NERC Glossary term “System”. The locations where “System” can be found in the Standard are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Individual
Sunitha Kothapalli
Puget Sound Energy, Inc.
Yes
We Appreciate SDTs efforts in bringing clarity to the TPL standards.
Yes
Group
Bonneville Power Administration
Yes
1. If current study is performed to assess the system, there is no need to supplement with past studies. • Suggested language for R2.2:- For the planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed and be supported by the following annual current study or qualified past studies as indicated in Requirement R2, Part 2.6 2. Load models should be consistent across the region • Suggested language for R2.4.1:- System peak load for one of the five years. System peak load levels shall include a the latest load model developed by the regional planning coordinator which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. 3. R2.5 is redundant and should be deleted. It is already included in R1.1.3 and R2.6.2. 4. R3.5: This standard requires mitigating the consequences of extreme events. Requiring potentially very costly mitigation actions for very low probability event is unnecessary burden to utilities. • Suggested language for R3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. Evaluation of the risk, consequences and adverse impacts of the event(s) shall be conducted.
No
The VRF for R2 was changed from Medium to High without any explanation. Since the time horizon for R2 is Long Term Planning, BPA believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Group
Tri-State Generation & Transmission
Yes
No
Many of the sub-requirements of R2 do not warrant high risk VRFs, yet violation of any R2 sub-requirement would result in a “High Risk Factor” violation assessment. We believe that having so many sub-requirements can result in inaccurate overall severity classification. For example, skipping one study defined in R2.1.2 (Planning Assessments) for a particular time frame or load level would probably not result in a direct actual degradation in system performance, but would still result in a High Violation Risk Factor.
Change R1.1 to “System models used for Steady State and Stability Analysis shall represent:” Much

of what is in R1.1 is unnecessary for Short Circuit studies. In contrast, there are items not mentioned in R1.1 that are necessary for short circuit studies. R2.1.4 requires sensitivity analysis to study “a range of credible conditions that demonstrate a measurable change”. How will the required actions in R2.1.4 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? In R2.3, change the first sentence to read “The short circuit analysis portion of the Planning Assessment shall be conducted annually, using one of the cases described in 2.1.1, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6.” There appears to be no reason to perform short circuit studies for all three Near-Term Transmission Planning Horizon cases. R2.4.3 requires sensitivity analysis to study “a range of credible conditions that demonstrate a measurable change”. How will the required actions in R2.4.3 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? R2.7.1 remove the last bullet. We believe these programs are already factored into the load forecast, as they are associated with resource scheduling and planning load serving, and not transmission planning. In particular, DSM measures would fall under R2.4.1, and the term “new technologies, or other initiatives” The language of Requirement 3 unnecessarily repeats the language of R1 and R2. As now written, R3 states “For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.” R3 We recommend that the introductory language in Requirement R3 be changed to read “The studies in Requirement R2, Parts 2.1, and 2.2 shall be performed using models as defined in Requirement R1 in accordance with the following criteria.” We believe that Requirements 3.1 and 3.4 should be combined into R3.1, eliminating R3.4. It is redundant to have Requirement 3.1 say “perform R3.4”. We recommend that R3.4 be deleted and that R3.1 be replaced with: R3.1 Planning event studies shall be performed in accordance with “Table 1 – Steady State & Stability Performance Planning Events;” and shall be based on a supportable Contingency list. Comment: The content of 3.4.1 was intentionally omitted as it is redundant with R7. Also, the language “...more severe System impacts...” was intentionally omitted as it could be subject to a wide range of interpretations. Similarly, we recommend that R3.5 be deleted and that R3.2 be replaced with: R3.2 Extreme event studies shall be performed in accordance with “Table 1 – Steady State & Stability Extreme Events;” and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R3.2 language: Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Comment: As before, the language “...more severe System impacts...” was intentionally omitted as it could be subject to a wide range of interpretations. We recommend removing the second bullet of R3.3.1, “Tripping of Transmission elements where relay loadability limits are exceeded” for the following reasons: 1. There is currently no tool to model relay loadability characteristics in Steady State analysis. 2. Requirement R3.3.1 would require inclusion of relay models in modeling data that are not currently provided. MOD-012 does not require impedance or overcurrent relay models to be submitted. 3. In Requirement 3.3.1, the second bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. At best an individual point could be chosen to model relays based on a selected power factor. We recommend changing the opening text of Requirement R.3.3.2 to say “Simulate the expected automatic or manual operation...” Subrequirement R4.1.2 represents a tremendous increase in dynamic modeling complexity. Modeling relay action during apparent impedance swings would require inclusion of impedance relay models in modeling data that are not required to be submitted in MOD-012. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. We believe that Requirements 4.1 and 4.4 should be combined into R4.1 as shown below and R4.4 should be deleted. It is redundant to have Requirement 4.1 say “perform R4.4.” We recommend R4.1 language be revised to read as follows: R4.1 Planning event studies shall be performed in accordance with “Table 1 – Steady State & Stability Performance Planning Events;” and shall be based on a supportable Contingency list. Comment: The content of 4.4.1 should be omitted as it is redundant with R7. Also, the language “...more severe System impacts...” should be omitted as it could be subject to a wide range of interpretations. Similarly, R4.5 should be deleted and R4.2 should be replaced with: R4.2 Extreme event studies shall be performed in accordance with “Table 1 – Steady State & Stability Extreme Events;” and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R4.2: Should the extreme

event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the even(s) shall be conducted. Comment: As before, the language “…more severe System impacts…” was intentionally omitted as it could be subject to a wide range of interpretations. Clarify the first bullet in Requirement R4, part 4.3.1 by changing it to “High-speed (less than 1 second) reclosing, where the fault has cleared, and high-speed reclosing into the permanent fault , but in each case only if high-speed reclosing is utilized”. In Requirement R4, part 4.3.1, third bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. Existing applications do have impedance relay models, but these models do not model many relay capabilities– for example, non-circular protection regions and load-encroachment. We recommend removing this bullet. The comment statement we made above referring to R4.1.2 also applies to R4.3.1. MOD-012 does not require reclosing relay model data to be submitted. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. Furthermore, there is not a standard built-in reclosing relay model in current stability simulation tools. Comments regarding Table 1- We assume the headnote i. to Table 1 - “The response of voltage sensitive Load…” - means that studies must not rely on end-user load tripping to meet the performance requirements defined in TPL-001-2 but that it should be modeled (when known) so that its occurrence would be evident. We don’t see the need to apply Footnote 12 to only certain contingency categories or certain events in categories. Recommend putting the footnote in the column header just as with Footnotes 1, 2, 3, and 4. Recommend changing “utilized” in Measurement M3 to “performed.” Recommend changing “utilized” in Measurement M4 to “performed.” Modify Measurement M7 to “Each Planning Coordinator shall provide dated documentation on roles and responsibilities of its Transmission Planners, such as…” The deleted phrase, “in conjunction with each of its Transmission Planners,” appears to be unnecessary.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
1. In requirement 4.3, the high speed recloser time of 1 second is too restrictive. We suggest that the time be expanded to 2 seconds to capture all reclosing operations that might impact stability studies. We interpret the use of bullet points in Requirement 4.3.1 to mean that any one of the statements can be included in the analyses. In this requirement, the use of bullet points should be removed and replaced with language that requires all of the statements to be included in the analyses. We strongly believe that the language needs amended in requirement 4.3.1, such that, we will reconsider our voting position. 2. In Table 1 labeled Steady State and Stability Performance Extreme Events we contend that the change to “relay failure” is unnecessarily limiting. The previous use of Protection system was satisfactory. Protection System is a defined term and encompasses many components that may fail and not just the relay. 3. In table 1 Steady State & Stability Performance Planning Events under P5 “non-redundant” needs to be better defined. We suggest saying in a footnote that two devices do not need to be identical in order to be redundant. Redundant relays or relay schemes need to have the same performance level to be considered redundant but do not need to be identical equipment.
No
ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons: 1. VSL for R1 a. Under the last “Severe” VSL, the word “latest” should be removed to be consistent with the language in Requirement 1. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement” 2. VSLs for R2 a. To be consistent with the language in Requirement 2, suggest modifying the last “Severe” VSL to state “The responsible entity failed to prepare an annual Planning Assessment of its portion of the BES” 3. VSLs for R3 a. Under the last VSL under the “High” category, the word “perform” should be replaced with “simulate” to be consistent with the requirement. (e.g. “The responsible entity did not simulate Contingency analysis as described in Requirement R3, Part 3.3.”) 4. VSL’s for R4 a. Under the last VSL under the “High” category, the word “perform” should be replaced with “simulate” to be consistent with the requirement (e.g. “The responsible entity did not simulate Contingency analysis as described in Requirement R4, Part 4.3.”). 5. VSLs for R6 a. To be consistent with the language in Requirement 6, suggest modifying the “Severe” VSL to state “The responsible entity failed to define and document, within their Planning

Assessment, the criteria or methodology used in the analysis to identify System instability for conditions, as described in Requirement R6." 6. VSLs for R7 a. Suggest adding the following language to the end of the "Severe" VSL; "for the Planning Assessment", to be consistent with the requirement. 7. VSL for R8 a. Under all four categories of VSLs, any reference to "Planning Assessment" should be changed to "Planning Assessment results" to be consistent with the language in Requirement 8 (or more appropriately, the term "results" should be removed from Requirement 8). This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" b. Under the "Lower" VSL, it is unclear why there is a 30 day timeframe for the first VSL, while the "Moderate", and "High" VSLs have a 10 day timeframe. Based on FERC recommendations, suggest making the timeframe for all four VSL s, 10 day increments. c. VSLs need to be developed to deal with a violation of Part 8.1 (i.e. the PC or TP failed to provide a documented response to that recipient within 90 calendar days of receipt of those comments)
1. Requirement 8 and 8.1 uses the language of "Planning Assessment results". This language is not defined in the section of the standard that defines the terms of use. For consistency "Planning Assessment results" should be replaced with "Planning Assessment". 2. Requirement 2.1.5 has statements that are ambiguous. What is considered major transmission equipment? What is an entity's "spare equipment strategy"? The requirement is not clear as to how many power flow models are required (one per piece of "major transmission equipment" without a spare, or one model with every piece of "major transmission equipment" without a spare being out of service)? As written, if an entity has no "spare equipment strategy" they could be exempt from this requirement. 3. We interpret the use of bullet points in Requirement 3.3.1 to mean that either one of the statements can be chosen. This requirement should be written where all the bulleted statements are included in the analyses.
Group
MRO's NERC Standards Review Forum
Yes
No
The NSRF recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". We do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.
The NSRF recommends that the term, "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6
Individual
Michael Moltane
ITC
Yes
No
ITC recommends revising R8 VSLs as follows: Lower VSL The responsible entity distributed its Planning Assessment to known adjacent Planning Coordinators and known adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request. Moderate VSLs The responsible entity distributed its Planning Assessment more than 30days but less than 60 days after subsequent requests by adjacent Planning Coordinators or adjacent Transmission Planners who were not sent copies upon completion of the Planning Assessment. OR, The responsible entity distributed its

Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request High VSLs - eliminate this section. i.e., no high VSLs only lower,moderate and severe Severe VSLs The responsible entity distributed its Planning Assessment to functional entities having a reliability related need, adjacent Transmission Planners and adjacent Planning coordinators who requested the Planning Assessment in writing but it was more than 60 days following the request.
ITC COMMENTS on TPL-001 vote ITC will reluctantly vote to approve the draft standard. While we have concerns, we are voting to approve this standard because we believe the positive elements outweigh the portions of the draft standard that we object to. It is important that the improved requirements that effectively “raise the bar” over the existing standard should become effective sooner rather than later. A negative vote, which might cause a further delay in implementation of the standard, would be the least desirable outcome. However, we still believe that the VSL that would find that an entity had committed a “severe” violation for failure to distribute its planning assessment to an adjacent Transmission Planner or Planning Coordinator has the potential to overly punish a simple error in oversight. We would agree that willfully withholding an assessment from a neighbor or a valid requestor justifies a severe violation but an administrative or clerical oversight does not. For example, it might escape our attention that an entity, particularly a smaller one, registers as a TP or TP. As far as we know, there is no requirement that a registrant, or even one who de-registers, must notify an “adjacent” TP or PC of their change in status. As written, the standard requires you be found in “severe” violation, even if that new entity fails to notify you of their change in status. You would still be in severe violation even if they later ask for your planning assessment. Even if the standard passes, we request that this VSL be fixed to make the distinction between an administrative error and willful neglect. Our response to question 2 offers a suggested method to do this.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
R1 does not seem to address errors in data that have been introduced in the latest model data. In addition, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five year delay in the effective date for short circuit studies for parts 2.3 and 2.8 of R2 because these studies are not required in the current Version 0 standards.
Individual
Joe Petaski
Manitoba Hydro
No
-R2.1.4 and R2.4.3: ‘Expected transfers’ should be replaced with ‘Firm Transmission Service and Interchange’ to correlate to R1 (R1.1.5 states ‘Known commitments for Firm Transmission Service and Interchange’ must be represented in system models). -R2.1.4 and R2.4.3: ‘Generation additions, retirements, or other dispatch scenarios’ should be deleted since generator connections are required to be studied as specified in FAC-002. -R2.1.5: The Standard Drafting Team needs to clarify R2.1.5 for a scenario where a spare transformer is available but is used to replace a failed transformer say one month before the expected system peak. If this scenario occurs, does the Transmission Planner need to study the impact of the unavailability of a transformer to cover the situation that could occur if a second transformer failure occurs before the expected system peak? -R2.4 and R2.5: ‘current or past studies’ should be replaced with ‘current annual studies or qualified past studies’ to be consistent with R2.1. -R2.5: The wording allows the PC/TP to determine what is ‘material’. This could lead to large differences in generator additions or changes that would be included. The Standard Drafting Team should consider registration criteria to set size limits for this sensitivity. -R2.7.3: What is the required timeframe? How long will Non-Consequential Load Loss or curtailment of Firm Transmission Service be allowed with this exception? -R3.3.1 Second bullet: If relay loadability limits are exceeded, the protection would be in violation of PRC-023. This standard should assume this situation would not

occur. -R3.5 and R4.5: What is the point of identifying mitigating measures for extreme events when there is no Requirement to implement such measures? -R4: The first sentence in R4 requires one to perform the Contingencies in Table 1. This sentence should read 'For the Stability portion of the Planning Assessment, as described in Requirement R2, -Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform Contingency analyses based on the list of Table 1 Contingencies defined in Requirement R4, Part 1'. -R4.1.2: A generator should not be allowed to pull out of synchronism for P2.1. -R4.1.3: The Planning Coordinator and Transmission Planner should have to document the damping criteria used to access 'acceptable damping'. -R8: Why 30 days for 'any functional entity that has a reliability related need and submits a written request'? The timeframe should be 90 days as it is for 'adjacent Planning Coordinators and adjacent Transmission Planners'. -Table 1-Steady State and Stability Performance Planning Events, Category P5, now includes "non-redundant" relay in the Event column. What is meant by non-redundant relay? The term "non-redundant" is not a defined term. -Regarding Note 12- An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments. -Non-Consequential Load Loss is only allowed in very unlikely scenarios as a last resort that would cause local load issues. When used as intended by the drafting team (ie. as a last resort) Non-Consequential Load Loss would have no negative effect on the network since it would only be used to improve network conditions like low voltage or line overloads. Should NERC be worried about documenting this use of Non-Consequential Load Loss? NERC should focus on network issues, not local load issues. -NERC should remove the last part of Note 12: "and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." It is inappropriate for NERC to mandate an open stakeholder process and Manitoba Hydro cannot support this mandate. In addition, it is unclear how NERC can mandate an open stakeholder process and who that might include. FERC has defined such a process in Order 890. Is that what is envisioned?
No
-The language "latest data" is used in the Severe VSL for R1, however "latest" was removed from R1 and M1. "Latest" should also be removed from the Severe VSL for consistency. -What is the rationale for changing the preparation of the Planning Assessment (R2) VRF to High from Medium? The R2 VRF should remain at Medium. The R2 Time Horizon is Long-term Planning, an entity can rely on qualified past studies to complete the Planning Assessment and the actual performance of studies (R3 and R4) have Medium VRFs. -Please explain the phrase 'completed annual Planning Assessment' used in the Severe VSL for R2. What is the reason for the change in VSL for having a 'completed annual Planning Assessment'? -Can the drafting team please explain why defining the criteria for steady-state voltage limits etc. in R5 has a VRF of medium? Criteria development is administrative, therefore the VRF for R5 should be Low. Setting the VRF for R5 to Low would be consistent with the Low VRF for R6 that relates to defining the criteria for cascading. -Requirement 8 is an administrative burden that adds little to improve reliability. The revisions made to the VRF and VSL for Requirement 8 further exacerbate this administrative burden. One could conclude from observation of the VSLs and VRFs, that Requirement 8 was the most important requirement of TPL-001-2. The drafting team should simplify the VSLs and revert R8 back to a low VRF. Where are the timeframes used in the VSLs for Requirement 8 coming from? Requirement R8 does not specify these timeframes.
-Why was the Near Team Transmission Planning Horizon definition moved to the Glossary prior to TPL-001-2 approval? -The definition of Non-Consequential Load Loss should not contain '(2) the response of voltage sensitive Load' because voltage sensitive load is not load that is lost (it is load that is still served). -M8: Why 30 days for 'any functional entity who has indicated a reliability need'? The timeframe should be 90 days as it is for adjacent Planning Coordinators and adjacent Transmission Planners.
Group
Hydro One Networks Inc.
No
Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the

April 15, 2011, draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft (see our response to Question 3).
A. Regarding Requirement 1.1.2, assessment of “known outages... with a duration of at least 6 months”, are dealt with in the operational studies rather than planning studies. In addition, any adverse impact that these outages might have, are mitigated by operational decisions rather than “planning” decisions within a 6-month horizon. It is suggested to move this requirement out of TPL standards and instead include it a relevant operational standards. B. The statement in R 2.1.4, “must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response”, leaves room for very different interpretations by PCs and TPs as to the number and type of required sensitivity studies. Are all interpretations, based on the engineering judgment of the PC and TP, acceptable? C. The language of R 2.1.4 and 2.4.3 allowing to perform one or more sensitivities appears to be inconsistent with the language in R 2.7.2 which requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study? D. The language of Requirement 2.1.5, “spare strategy”, appears to be open-ended regarding the number of permutations to be analyzed. It is suggested to move this requirement out of TPL standard and instead have this issue dealt with in the operational standards. E. In R 2.2, the statement “be supported by the following annual current study, supplemented with qualified past studies” should be replaced with a similar statement in R 2.1 which says: “be supported by current annual studies or qualified past studies”. F. In R 4.1.1, “For planning event P1: No generating unit shall pull out of synchronism” is too restrictive. In many cases a P1 event may result in instability of a small nearby generator without a significant impact on the reliability of BES. The same requirement states that “A generator being disconnected from the System … by a Special Protection System is not considered pulling out of synchronism”. If rejection of ANY generator by SPS is acceptable, why should instability of a small generator, resulting in its disconnection by its protection without a severe impact on the system, be unacceptable in all circumstances? If this requirement is unchanged, it dictates the addition of an SPS (Generation Rejection) for any unit that might go unstable without any benefit for the reliability of the BES. G. In Table 1, Event 1 of Category P2 and related Footnote 7 (simulation of LEO condition) are not clear (concern with the use of the word “possibly”). If the intension is to simulate LEO condition of tapped lines, this should be clearly stated in the table (without reference to “Opening of a line section” and use of different language in the footnote).
Individual
Tony Eddleman
Nebraska Public Power District
No
The existing TPL-001 through TPL-004 Standards and Requirements are clear and concise. The new merged TPL-001-1 Standard and Requirements is no longer clear and concise. Further, the modification made to allow an SPS to trip a remote generator for an N-1 (TPL-002) type of event is a degradation of system reliability. Transmission system facilities should be added to maintain stability for a new generator interconnection for any N-1 Category B event. An SPS should not be relied upon for a Category B event, an SPS should only be allowed for Category C & D (TPL-003 & TPL-004) type events.
No
No comments.
N/A
Individual
Robert Casey
Georgia Transmission Corporation
Yes
Yes

All of our prior issues have been addressed.
Group
BC Hydro
Yes
BC Hydro agrees with merging the standards together into one and we feel the new version brings further clarity to the annual planning assessment. BC Hydro would vote Affirmative for bringing clarity, however we do not believe the rewording in Footnote 9 is clear which is why we are voting Negative. Footnote B, as approved by the NERC Board of Trustees on February 17, 2011 was reworded as Foot Note 9 in the proposed TPL 001-2 draft 7 amendment. This rewording still does not clearly define what impact the proposed revision would have on the curtailment of firm transfers in the regional entities.
Individual
Jonathan Appelbaum
United Illuminating
No
a. 2.6.2 - What was the intent of this change? The old language seemed to work. The language should not be changed from the previous version. b. For 2.8.2 - Was the phrase changed to reflect modifications of facilities? If so the requirement should be modified to read “Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures with respect to modifications of facilities. Otherwise the requirement is unclear. c. For Section R8.1 - the proposed requirement conflicts with a long standing stakeholder process in our area which posts study results and allows comment within a defined period before studies are finalized. If this section is to be retained then it should be modified to only allow comments on Transmission studies less than one-year old. Requirement 8 and 8.1, should be revised to include a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. d. With respect to Table 1 – We suggest adding an event 6 to P1 to address the contingent loss of back to back HVDC Facilities. If not added to P1 then this event needs to be added somewhere in the standard. e. We don’t agree with footnote 7 specifying that only one end of the line should be open for this condition. If the SDT is to keep this concept make P2 event 1 simply say “Opening one end of a line section w/o a fault” and delete the footnote. The existing footnote is unclear due to the use of language such as “possibly”.
Yes
Individual
Andrew Z.Pusztai
American Transmission Company, LLC
Yes
No
ATC recommends that the VRF for Requirement 8 remain “Low”, rather than be changed to “Medium”. ATC does not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.
Individual

Michael Jones
National Grid
No
R2.8.2 We recommend this requirement be clarified with the following modification: The Corrective Action Plan shall: 2.8.1. List System deficiencies and the associated actions needed to achieve required System performance. 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of planned modifications to System Facilities and Operating Procedures.
No
R 2.0 We recommend that the VRF for this Planning Requirement remain at “Medium”. The risks associated with Planning Requirements have a longer time horizon for corrective action than, for example, those risks associated with much shorter Operational time frames.
R 1.1.2 We recommend the known facility outage duration be defined as facility outage durations lasting at least twelve months. R 1.1. (page 4) System models shall represent: 1.1.1. Existing Facilities 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six twelve months. 1.1.3 …… R 2.1.4 We recommend that this requirement be eliminated. We do not see the value of this additional analysis when the number, type and severity of the sensitivity tests are not well defined. These tests are then used to define Corrective Action Plans in cases only where multiple tests show performance deficiencies. R 2.1.5 Spare equipment strategies are typically designed to prevent long outages (possibility a year or more) of equipment with very long lead times. Any such strategy “could” result in these long outages depending upon the number of failures that may be postulated. This requirement is misleading and we thus recommend it be eliminated. R 2.2 We recommend the language for R 2.2 should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." R 2.6.2 We recommend that the wording of this requirement remain unchanged. R 2.7.1 This portion of the requirement provides a list of “acceptable” Corrective Action Plans. It provides equal weight to infrastructure reinforcements and Special Protection Systems as means to mitigate violations resulting form single or multiple contingencies at both the EHV and HV levels. National Grid’s position is that a national standard should not endorse the use of Special Protection Systems as corrective actions to mitigate single contingency violations. Local Northeast Planning Criteria indicates that special protection systems (SPS) shall be used judiciously and may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ a SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. We are further of the opinion that specific methods of correcting system performance deficiencies should not be specified in a National Standard. We thus recommend that the Corrective Action List be eliminated from this requirement as illustrated below. 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. R 2.7.2 We feel that this requirement and requirement R 2.1.4 adds ambiguity to the process as we have indicated above. We thus recommend that this requirement be eliminated. R 3.3.1 We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded” Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R 3.4.1 We would recommend the following addition as a clarification to the required information exchange: 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. 3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their respective Systems are

included in the Contingency list. R 8.1 National Grid's concern regarding this requirement stems from the apparent open ended time frame afforded report recipients in their review of the Planning Assessment. This has the potential to stall the review process. National Grid thus recommends that any recipient of the Planning Assessments be given a specific time period for their response as indicated in R 8.1 below. R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, and adjacent Transmission Planners, within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [Violation Risk Factor: LowMedium] [Time Horizon: Long-term Planning] 8.1. The recipient of the Planning Assessment results shall provides documented final comments on the results within 90 calendar days of receipt of the Planning Assessment. The respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Table 1 Steady State & Stability Performance Planning Events (Page10). The event description for Category P2 Event 1. along with the accompanying footnote 7 (Page 14) creates some confusion for multi-terminal lines. We recommend that Footnote 7 be eliminated and the event description be changed as follows: Category Initial Conditions Event P2 Normal System 1. Opening of a single load interrupting device at one terminal of a line without a fault. Table 1 (Planning Events and Extreme Events) Footnote 12 (Page 14). We are concerned that additional stakeholder process indicated in Footnote 12 has the potential to stall the Planning Assessment review process. We recommend that reference to this new process be eliminated from the Footnote. Our additional, concerns with Footnote 12 are addressed in comments originally provided by ISO-NE. We agree with their following comments : The following language for Footnote 12 is proposed: "Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems." If Footnote 12 in Table 1 must be retained, the following language is proposed: "An objective of the planning process shall be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: a. Interruptible Demand or Demand-Side Management b. Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documented c. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)"
Individual
Tim E. Ponseti, VP
TVA TP&C
Yes
Yes
TVA - has following comments: TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. In R4.1.1, TVA is concerned that no generating unit (including distributed generation) shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES. Table 1 contains both planning events and extreme events. Suggest labeling the planning events as Table 1 and the extreme events as Table 2 to help reduce confusion. VSL for R1 does not seem to address issues where data errors have been

introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past models. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Group
Entergy Services
Yes
Yes
Footnote 12 to Table 1 concerning non-consequential load loss should be clarified. The existing language will result in difficulties in proving compliance. Suggested language would be: “Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of a P1 or P2 event and where the location of the planned loss of Demand is limited to those Transmission Facilities made radial.
Individual
Michael Falvo
Independent Electricity System Operator
No
IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote ‘b’ to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote ‘b’ could be approved. In light of FERC’s request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC’s ruling on NERC’s petition seeking approval of the transmission planning standards that contain the revised Footnote ‘b’ to Table 1.
No
See our response to Q1.
See our response to Q1.
Individual
Alex Rost
NBSO
No
Items that, if not addressed, will likely cause a negative vote from NBSO: R2.2 differs from R2.1, R2.3, R2.4 and R2.5 since R2.2 does not state that the annual assessment of the Long-Term Transmission Planning Horizon portion of the steady state analysis can be supported by qualified past studies. Likely this omission is an oversight, but unresolved it can cause significant burden with little gain in reliability. Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote: The language of requirements R2.1.4 and R2.4.3 allowing the performance of one or more sensitivities appears to be inconsistent with language in R2.7.2 that requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. R7 (and M7) seem to indicate that the PC is ultimately responsible for determining the individual and joint responsibilities for performing the required planning assessment studies, with the expectation to consult and come to agreement with its corresponding TPs, but this interpretation is not clear. The correct interpretation of this requirement is important for resolving situations where a PC and TP do not agree on the assignment of responsibilities. Suggested wording: “Each PC shall work in conjunction with each of its TPs to determine and identify...” The language in R8 is unclear. One point of confusion relates to which entity is responsible for sending their Planning assessments to other entities. For example, who does a PC distribute their planning assessments to?: -Adjacent PC?

(Seems to be clearly addressed) -TPs within its PC footprint? (Not clearly covered by the language in R8) -TPs adjacent to its PC footprint (Not clear if this is the responsibility of the PC, TP or both) In addition, the language in R8.1 appears to offer unlimited opportunity to request response to comments on any past assessment, long after their release. Providing limits in the langue of R8.1 is recommended in order to avoid unnecessary burden on PCs and TPs for little gain in reliability or constructive stakeholder involvement.
Items that, if not addressed, will likely cause a negative vote from NBSO: NBSO believes that R1.1.2 is more appropriately addressed in the operational timeframe. Perhaps more appropriate alternatives could include: -only considering planned outages with durations of one year or more (in-line with typical planning timeframes), or -requiring that facilities with planned outages lasting over the complete duration of time period being studied be modeled out of service. R2.1.5 may significantly increase the demands of the planning assessments with little gain in reliability. Depending on interpretation, R2.1.5 could exponentially increase the work load of the annual planning assessment. NBSO interprets the intent of R2.1.5 to require that entities have, review and evaluate their spare equipment strategies. Perhaps the assessment of a spare equipment strategy would be more appropriately addressed in a separate standard. Further, categories P0, P1 and P2 do not reference footnote 9 in the Initial Condition column. NBSO is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service under the N-1 conditions before the application of category P0, P1 and P2 events. This last sentence states: "…with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." Table 1, note b should be modified to allow for the loss of Firm Transmission Service. This addresses cases where Firm Transmission Service is lost in direct consequence to the event (e.g. loss of one DC pole, an interface comprised of a single line, a bus fault that clears multiple lines in an interface, etc...) Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote: The definitions of "near-term transmission planning horizon" and "year one" have been removed from the standard, yet they are still used in draft 7. Further, the definition of these terms is being filed as part of another project. NBSO is concerned with endorsing a standard based on terms whose definitions may change independently of this project. For R7, NBSO is concerned that one entity may be found noncompliant should another entity fail to meet their agreed upon responsibilities. For example, a PC may be relying on the results from a TP's studies to complete its own planning assessment, but the TP did not meet their responsibilities. In this case, the PC should not be found non-compliant for an incomplete planning assessment due to the failure of the TP to meet their responsibilities. Contingencies on back to back HVDC facilities are not addressed in the standard.
Group
Western Area Power Administration
No
We concur that the standard is an improvement over previous drafts, but we vote "No" to the existing draft and request additional clarifications and/or modified language for a re-circulated vote prior to adoption. The following are areas where we suggest improvement or have questions: Please further define Consequential and/or Non-Consequential Load Loss: Does the Consequential Load Loss definition include underfrequency or undervoltage load shedding installed to protect transmission system reliability? Does the Consequential Load Loss definition include load tripped by a Special Protection System (SPS) or a Remedial Action Scheme (RAS)? Either how underfrequency and undervoltage load shedding or how load shedding by a RAS relates to Consequential Load Loss should be clear in the Consequential and/or Non-Consequential Load Loss definition of the approved version of this NERC standard. Why is Near-Term Tranmission Planning Horizon deleted from the definitions of Terms Used in this Standard, yet it is used throughout the standard? This definition should remain. R1.1.5: How are "known commitments for Firm Transmission Service" to be modeled and tracked in power flow cases? Is it acceptable for Transmission Planners to simply assume what the ultimate sources and ultimate sinks are for each firm transmission service commitment or are Transmission Planners to know exactly which ultimate sources and ultimate sinks are associated with each commitment and to track each one accordingly in each power flow case? Assuming the intent here is reliability based and not marketing based, is the application of Firm Transmission intended to apply to reliability designated 'paths'? Most all Firm Transmission service contracts have caveats for unplanned interruption and such agreements should qualify as "re-dispatch" per Footnote 9? R2.1.5: If a group

of utilities were to develop and manage among themselves a coordinated spare equipment program, such that the risk to any one of its participating entities of experiencing a significant unavailability for any major Transmission equipment that has a lead time of one year or more is deemed not significant, then would those utilities still have to do the studies required by R2.1.5 to evaluate the system impact of extended outages of such equipment? Scenario for Clarification: Short of spare equipment for items with a greater than 1 yr lead time, assessment studies are required to include sensitivities and operating plans for sustained loss of these equipment items, as a prior outage. For example, if an EHV facility is lost for more than 1 yr, and firm transmission interruption is not allowed, it appears the only compliant alternative (to a redundant facility) is a redispatch plan that is well documented and accepted by all stakeholders, per Footnote 9. R2.3: Is only the 5-year Near-Term Transmission Planning Horizon case required for the annual short-circuit analysis? R2.4.1: How is the dynamic modeling of induction motor Loads to be developed by the Transmission Planners? Is it acceptable for Transmission Planners to assume the same induction motor modeling as has generally been assumed and applied by most Transmission Planners throughout the Western Interconnection or will the induction motor modeling have to be based upon the type and amount of actual induction motors installed in the system? R2.5: Does NERC have a particular technical rationale about what determines "proposed material generation additions or changes?" R2.6.2: Does NERC have a particular technical rationale about what determines "material changes?" R2.7.3: Please define "beyond the control" under Definition of Terms Used in Standard. This is an important concept. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If the stakeholder rate payers do not approve expenditures for facility improvements required to eliminate non-consequential load loss, is this beyond the control of the Transmission Planner? Rate payers should be able make the ultimate free market choice determination of risk versus cost associated with their reliability. Otherwise market interests (particularly generation) disproportionately pressure excessive reliability based improvements that must be borne by all rate payers. R3.3.1: Please define "relay loadability limit" under Definitions of Terms Used in Standard. This is an extremely important concept. This term has been used quite commonly for decades and is now used in this latest proposed standard. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If PRC-023 is met whereby all "relay loadability limits" are set at least 150% of the highest thermal limiter (0.85 voltage and 30 lagging powerfactor) this sensitivity would justifiably not be needed so long as verification is shown that no element overloaded greater than 150%. R3.1 and R3.4: The interrelation between these two paragraphs needs additional clarification. R3.1 calls for verification via studies that the BES meets Table 1 performance criteria based on the contingency list resulting from R3.4. However, R3.4 states that the contingency list used to meet R3.1 only need include "Those planning events in Table 1, that are expected to produce more severe System impacts on…..the BES" and the associated "rationale" for those chosen contingencies. Is NERC suggesting that the studies do not need to include all contingencies based on Table 1, so long as ample "rationale" is provided? However, the Transmission Planner must provide studies to determine if every contingency of Table 1 meets performance requirements. How are the "more severe" contingencies determined if the Table 1 contingencies are not evaluated comprehensively? It seems R3.4 could be eliminated and the contingencies be based simply on Table 1. Please define "more severe", relative to less severe under Definitions of Terms Used in Standard, in an effort to help evaluate the suitability of a particular contingency for inclusion on this list. Looking at context, it appears that the purpose of this statement is to ensure that the worst contingencies are studied. Is the intent here simply to allow a given contingency to cover for a less severe or similar contingency and avoid duplicate simulations? R3.4.1 and R4.4.1 Please include and define a reasonable number of contingent buses into adjacent systems that should be considered. No more than 2 are recommended for the standard. R3.5 and R4.5: How many of the "events in Table 1 that are expected to produce more severe system impacts" should the required evaluation identify and evaluate? To what extent should the evaluation focus on the "other" Extreme Events described under items 3.b and 2.f in Table 1, particularly if existing disturbance reports in the Western (or Eastern) Interconnection have recorded and evaluated the occurrence of particular events that have already created cascading? Because the requirement seems to involve a check for Cascading, perhaps some clarity could be provided with respect to the NERC definition of "Cascading." In particular, in the Cascading definition, how widespread is "widespread;" is the phrase "electric service interruption" only about the loss of firm load or could it also be only about the loss of firm generation or only about the loss of firm transmission service or is it about some combination of loss of firm load, loss of firm generation, and loss of firm transmission service; how large an area is meant by the expression "spreading beyond an

area predetermined by studies” when the simulations that analyze the initiating Extreme Event will model the entire Western (or Eastern) Interconnection? So how does the study determine that the sequentially spreading service interruption has spread beyond the entire Western (or Eastern) Interconnection that is modeled in the simulation? Or is the term “area” meant to describe only that part of the Western (or Eastern) Interconnection that the Transmission Planner has evaluated for system impacts while ignoring impacts to the rest of the Interconnection? Table 1 – Planning Events, Steady State Only Note i: “The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event” seems to be included as items 2) and 3) under the Non-Consequential Load Loss definition. So, it seems acceptable to use this form of load loss to meet the stability performance requirements. However, the “Steady State Only” note i in Table 1 specifically does not allow its use to meet steady state performance requirements. Therefore, the “Steady State Only” note i in Table 1 should clarify why it seems acceptable to use it to meet stability performance requirements but not to meet steady state performance requirements. Table 1 – Planning Events, Category P2: Category P2 seems to include an unrelated mix of planning events ranging from a seemingly benign event (i.e., opening of a line section without a fault) to what would seem to be much more severe events (i.e., bus section fault or internal breaker fault). A clarification of why these planning events were lumped into the same Category P2 would be helpful to the Transmission Planner. Also, does the language in footnote 7 (i.e., “opening one end of a line section without a fault on a normally networked Transmission circuit …”) mean that P2-1 (“opening of a line section without a fault”) should be modeled as an open-ended line section? Table 1 – Planning Events, P2-2 (EHV) and P2-3 (EHV): For each of these planning events, its corresponding “Non-Consequential Load Loss Allowed” column should include a footnote 12 with each of the “No” boxes, similar to that allowed under the seemingly much less severe event P2-1 (“opening of a line section without a fault”). Otherwise, please explain why the seemingly much less severe P2 event (P2-1) has a footnote 12 exception for Non-Consequential Load Loss Allowed but the two seemingly more severe P2 events (P2-2 and P2-3) do not. Table 1 – Planning Events, P4-1 through P4-5 (EHV): For the stuck breaker planning events of P4-1 through P4-5 on the EHV system, their corresponding “Non-Consequential Load Loss Allowed” column should include a footnote 12 with their “No” box, similar to that allowed under the seemingly much less severe N 1 planning events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe stuck breaker events (P4-1 through P4-5) do not. Table 1 – Planning Events, P5-1 through P5-5 (EHV): For the relay failure planning events of P5-1 through P5-5 on the EHV system, their corresponding “Non-Consequential Load Loss Allowed” column should include a footnote 12 with their “No” box, similar to that allowed under the seemingly much less severe N 1 events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe relay failure events (P5-1 through P5-5) do not.
Individual
Alice Ireland
Xcel Energy
Yes
Effective Date: The effective date section seems to imply that Non-Consequential Load Loss will not be permitted after the 84 month implementation period. We do not believe that was the drafting team’s intent and request that it be modified. Footnote # 12 in Table 1, in particular, seems to support our assumption that the team did not intend to disallow it. For reference, the footnote states: “12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load

Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." However, if it was the drafting team's intent to not allow Non-consequential Load Loss after the 84 month implementation period, we disagree and ask the team to reconsider. Particularly for rural areas, in some cases, this will be the only action possible. R2.1.4: a) We would like to see clarification on the term "sensitivity analysis". Is this in reference to seasonal models and differences in fuel availability? We would like more detail on how this is to be done so that it won't be left up to interpretation. b) We would like the drafting team to consider stratification of the tasks needed to perform a Planning Assessment. In our opinion, having both the TP and PC do exactly the same study produces tremendous and unnecessary duplication. Without stratification, the TPL-001 standard will continue to perpetuate the same paradigm used in the existing TPL-001 through TPL-004 standards. The NERC Functional Model makes a clear distinction between PC and TP functions/responsibilities. It is not clear why that distinction is not leveraged in the new TPL-001 standard. This will be particularly troublesome in areas where an ISO or RTO is the Planning Coordinator. In order for the RTO/ISO, as the PC, to be able to do their Planning Assessment, the Transmission Planners would have to provide a lot of detailed input data. So, in effect, both the PC and TP would be performing their assessment from the same data. It would make more sense if the RTO (as the PC) performed the required studies on the 500-345 kV network and the TP performed the required studies on everything below 230 KV. We also recommend the allowance for utilization of a regional assessment, instead of performing your own, due to individual entity resource constraints. R2.4.1: We would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the intent is for the model to contain a very detailed representation of the load system, then it may take a longer time to implement. R3.4.1: a) This type of coordination could be difficult due to other adjacent entities on different schedules and some may not have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? We would like the roles of the coordinators vs. the planners to be clarified in order to ensure that no work is being duplicated. b) PC's between regions, such as RTOs, are already coordinating for long term studies. In these cases, we feel the PC should alone be responsible for the requirements, rather than also the TPs. c) Can we get a clear definition of what apparent impedance swings means? We interpret it as rotor angle stability. R4.3.1: We would like to see that the detailed data is incorporated back into the NERC modeling processes and create a more detailed model with better accuracy. R8: We do not agree with the requirement to provide the assessment to every adjacent PC and TP because we fail to see the reliability benefit in doing so. However, we do agree that the PC and TP should be required to provide the assessment to any of these entities, if requested. Additionally, for entities that make such requests, we would like to have 90 days instead of 30 to respond. In many cases a non-disclosure agreement will have to be executed due to CEII classification of some information, and this can take several months.
Individual
Christine Hasha
Electric Reliability Council of Texas, Inc.
No
ERCOT ISO believes that the revisions do not go far enough in addressing previously submitted comments. As written this standard would require restructuring of the functions in the ERCOT Region because several requirements are being assigned to the PC that are currently performed only by the TPs. It would not provide any reliability benefits to have the ERCOT PC assume these functions. Specifically, the following requirements should be modified: R2.1.5 should be clarified to be applicable to TPs only since the ERCOT PC does not have the information necessary to perform this analysis; R2.3 and R2.8 should be clarified to be applicable to TPs only since the ERCOT PC does not perform this analysis (it is performed by the TPs in ERCOT); R4.1.2 should be clarified to only apply to TPs because the ERCOT PC does not have the modeling information necessary to perform this analysis. Additionally, R2.1.4 and R2.4.3 should be removed because the requirements are subjective and there are no actions prescribed to be taken based on the sensitivity results. The Load model requirement should be removed from R2.4.1 because this would be better addressed in a MOD standard. Alternatively, R2.4.1 should be rewritten as "System peak Load for one of the five years with expected dynamic load models." A concurrent requirement should be incorporated to mandate DSPs and TPs to supply dynamic load model data to the PC to perform the required studies.

No
ERCOT ISO believes that the VRF for R8 should be “low”. The distribution of the Planning Assessment is administrative in nature, the failure to distribute the Planning Assessment does not necessarily equate to not communicating the content of the assessment, and the consequence of not distributing the Planning Assessment does not immediately impact the reliability of the BES; thus it does not warrant a ‘Medium’ risk factor.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Requirement R1.1.5: Delete “and Interchange.” The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Individual
Kathleen Goodman
ISO New England Inc.
No
a. 2.6.2 - What was the intent of this change? The old language seemed to work. The language should not be changed from the previous version. b. For 2.8.2 - Was the phrase changed to reflect modifications of facilities? If so the requirement should be modified to read “Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures with respect to modifications of facilities. Otherwise the requirement is unclear. c. For Section R8.1 - the proposed requirement conflicts with a long standing stakeholder process in our area which posts study results and allows comment within a defined period before studies are finalized. If this section is to be retained then it should be modified to only allow comments on Transmission studies less than one-year old. Requirement 8 and 8.1, should be revised to include a limit on the comment period as follows: If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. d. With respect to Table 1 – We suggest adding an event 6 to P1 to address the contingent loss of back to back HVDC Facilities. If not added to P1 then this event needs to be added somewhere in the standard. e. We don’t agree with footnote 7 specifying that only one end of the line should be open for this condition. If the SDT is to keep this concept make P2 event 1 simply say “Opening one end of a line section w/o a fault” and delete the footnote. The existing footnote is unclear due to the use of language such as “possibly”.
Yes
We feel previous comments have largely been ignored by the Standards Drafting Team leading to a lack of support for the standard. Overall the standard should be more precise in its language. The following comments are provided for serious consideration with respect to revisions: Comments: From Section A.3 – the introduction please strike the word “probable” as shown below Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies This is deterministic contingency testing and this

word introduces probability into the standard where it does not belong. For R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be acceptable. Duration of known outages should be increased from six months to one year. For R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load. REMOVE INTERCHANGE from 1.1.5 - Definition of Interchange – The inclusion of Interchange requires designing for non-Firm service. In the NERC Glossary of Terms Used the term Interchange is defined as “Energy transfers that cross Balancing Authority boundaries.” It is meant to refer to energy transaction other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and are deemed highly interruptible and subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability under TPL-001. Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited or no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies “only” if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple condition sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed or revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. We agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." For 2.7.1 – We don’t believe this list provides value nor should it be included in the standard. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” In Table 1 - The fault descriptions must be clear. They must use “3-phase”, “single-phase-to ground”, or “2-phases-to ground” in the descriptions of a fault rather than SLG (a line is not a phase in electrical terms--single line to ground is not precise enough). In Table 1 - Where two elements are affected by a fault it must be clear whether the requirement is for a single-phase-to ground fault, or a 2-phase-to ground fault. They are different faults that will have different dynamic responses. For Table 1– add a footnote for the term generator to address the treatment of Combined Cycle Generators – “In addition to evaluating the loss of a single generator, the loss of all interrelated generators shall also be considered as a single contingency.” Operating experience has shown that trips of the entire CC facility often occur even on facilities that claim the combined cycle generators are independent. Where a category involves an initial condition representing the loss of a facility followed by an event represeting the loss of a facility such as P3, the standard must be clear as to the amount of time assumed between faults. An assumption may be 30 minutes, but the standard must not leave this unsaid. This clarity must be provided in the Table 1 Notes. In addition, the standard must be clear on the allowable re-adjustments between contingencies such as P3, or better, must be clearly limit the permissible re-adjustments. For example, it is not realistic to assume an unlimited amount of re-dispatch between faults—e.g. the allowable re-adjustment should be limited to actions that can be effectively implemented in less than 30 minutes, such as a, b, c, d, ..., and the amount of generation re-dispatch must not exceed the amount of future planned contingency reserve, or similar language. This clarity must be derivable from the Table 1 Notes.
Individual
Claudiu Cadar

GDS Associates, Inc.
No
1. Footnote a. Footnote should state “Draft 7” instead 2. Requirement R1 a. Time Horizon should include both Near-term and Long-term Planning 3. Requirement R2 a. Time Horizon should include both Near-term and Long-term Planning b. Requirement R2, Part 2.1 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. • The term “Qualifying studies” from the last sentence is referring to the qualified past studies, or the annual studies, or both actually? Suggesting adjusting the verbiage so it would not create confusion. • Subpart 2.1.4 - Requirement R2, Part 2.1.1 and Part 2.1.2 are referring to system conditions, not studies. The second sentence may be subject of non-objective interpretations and may generate burdensome and unrealistic amount of work. The requirement should state instead "For each of the system conditions described in Requirement R2, Part 2.1.1 and Part 2.1.2, the studies shall include sensitivity cases utilized to demonstrate whether there is any significant impact due to changes on the basic assumptions used in the model. The analysis, by case, may contemplate varying one or more of the following conditions:” • Subpart 2.1.5 - We suggest adjusting the time threshold of potential equipment unavailability in order to be consistent with the time frame for the "known Transmission outages". c. Requirement R2, Part 2.2 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. • While the Near-Term portion of the Planning Assessment details the premises of the study, the Long-Term is lacking in such thing. d. Requirement R2, Part 2.3 • Although both the steady-state and transient stability studies are required for the Near-Term and Long-Term, the short-circuit study is required only for the Near-Term. This is big disconnect, because there can be stability analyses conducted without a short-circuit assessment. • Breakers should be checked for their breaking capability, as well as to withstand the fault. All other disconnecting equipment, as well as current transformers in particular shall be also verified for their withstand capabilities. The current statement should be replaced with "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term and Long-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to assess performances of transmission elements affected by a potential increase of short-circuit contributions to fault” e. Requirement R2, Part 2.4 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. • Similar with 2.1, the last sentence should read "The studies should include the following conditions:" • Subpart 2.4.1 - We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concerned about the effort required to ascertain the dynamic response of the load. As for the “Loads that could impact the study area” the standard doesn't include any directions in how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area. • Subpart 2.4.3 - See comments from Subpart 2.1.4 f. Requirement R2, Part 2.5 • The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. g. Requirement R2, Part 2.6 • Subpart 2.6.2 - We agree with the suggested changes as responding to previous comments h. Requirement R2, Part 2.7 • Subpart 2.7.1 - We disagree with the implemented changes. The standard should not include examples. If needed, a white paper can accompany the standard. We suggest adjusting the last sentence to read “Such actions may include, but are not limited to, the following:” i. Requirement R2, Part 2.8 • This should apply to all disconnecting equipment and CT in particular with respect not only to their interrupting duty, but to their withstand capabilities also. See comment on Part 2.3. 4. Table 1 a. Footnote 9 • With respect to the Curtailment of Firm Transmission Service we suggest SDT to revise the language in order to be consistent with the Implementation Plan. 5. Measure M1 a. This measure it is hard to read. For simplicity, we suggest adjusting this measure to read "Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, and the models reflect the System conditions in accordance with Requirement R1." 6. Measure M7 a. The measure encompasses the particular scenario where the parties involved have reached an agreement for performing the required studies. In order to cover situations where the parties have not reach an agreement, the measure should read "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies all individual and joint responsibilities for

performing the required studies and Assessments in accordance with Requirement R7." 7. Compliance a. Data retention • The 5th bullet should read "The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5." • The 6th bullet should read "The documentation specifying the criteria or methodology used to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding since the last compliance audit in accordance with Requirement R6 and Measure M6." • The 7th bullet should be reworded in accordance with suggested changes at M7.
Yes
Agree in general.
N/A
Individual
David Thorne
Pepco Holdings Inc
Yes
Pepco Holdings Inc supports the proposed revisions.
Yes
Individual
Michael Lombardi
Northeast Utilities
No
Definition of Terms Used in the Standard The definitions of “Near-Term Transmission Planning Horizon” and “Year One” have been deleted from the standard, yet they are still used in draft 7. NU is concerned about voting in favor of this standard with these terms being defined by another project without a full discussion of the impact to this proposed standard. NU suggests repeating the definitions in this proposed standard. Requirement R1 NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. However, a more detailed guideline for developing base cases should be addressed by the requirements. By just modifying the language of requirement R1 to indicate that “P0” constitutes the initial system conditions does not address this concern in Draft #7. A more detailed guideline for base case development is needed. Requirement R8 The wording in requirement R8 needs to be amended to restrict comments to the most recent assessment only, for a limited period (say 3 months) after its release. The current wording appears to offer unlimited opportunity to comment on past assessments, long after their release. Footnote 7 It appears there is a discrepancy between Footnote 7 and Event P2-1. Footnote 7 could be eliminated by rewording Event P2-1 as follows: “Opening one end of a line section w/o a fault”. Footnote 12 NU did not agree with the clarification of Table 1 Footnote B of TPL-002 and did not vote for its approval. Therefore, NU does not agree with the same clarification being applied here for Non-Consequential Load Loss. For reference, below is NU’s comment on TPL-002 Table 1, Footnote B: “The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language”. General comment NU believes that a standard should contain statements and requirements that are direct and measurable. TPL-001-2 should not be an exception to this rule. Therefore, statements like “An objective” which appears in Footnotes 9 and 12 shall not be used.
Yes
The following previous comments that were filed by NU were not addressed by the SDT in the current draft. For NU to support the standard these comments should be addressed or reasons should be provided why they have not been addressed. Repeated below are NU’s comments that were filed for

the previous draft. Requirement R1, Part 1.1.2 NU requests that the six month duration stated by Requirement R1, Part 1.1.2 should be modified to one year duration to eliminate outages that occur within the “operational planning timeframe”. Requirement R1, Part 1.1.6 The phrase "required for Load" should be deleted as this confuses the issue. Requirement R2, Part 2.2 The language of Requirement R2 Part 2.2 seems to suggest that current annual studies are always required for the long-term steady state assessment. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Requirement R2, Parts 2.1.4 & 2.4.3 1) The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. 2) Requirement R2, Part 2.1.4 and Part 2.4.3 should clarify what is meant by multiple sensitivity studies and one sensitivity study. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study? Requirement R3, Part 3.3.1 NU feels that the last sentence of Requirement R3, Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: “Tripping of Transmission elements where relay loadability limits are exceeded.”
Individual
Marie Knox
MISO
Yes
No
Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain “Low”, rather than be changed to “Medium”.
Overall, we remain concerned that the revisions to the TPL standard are not on balance an improvement to the original. The document is not well organized topically, making it more difficult to navigate and understand. If the primary improvements sought in requirements for reliability planning were to increase system performance levels (no loss of firm demand) for certain multiple contingency events, and to ensure more stressed system sensitivities are analyzed, this can be accomplished in a much simpler revision. We do not believe that this standard as written improves the clarity of what is required, and therefore provides an opportunity for greater disputes between compliance monitors and applicable entities, and this is not a positive outcome. We also believe that the standard is too prescriptive as to what critical system conditions must be modeled, as these conditions vary considerably from system to system and within large systems. Table 1-Steady State and Stability Performance Planning Events, Category P5, now includes “non-redundant” relay in the Event column. What is meant by non-redundant relay? It is unclear if the SDT’s intent is to provide distinction between a back-up relay and a redundant relay. We recommend that the SDT provide a definition for the term “non-redundant”.
Group
Imperial Irrigation District
Yes
Yes
Previous TPL Standard balloting included the FERC Order that clarified footnote ‘b’, regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. 1. R2 (2.5): The value of assessing system stability for years 6-10 is questionable. Stability studies should be conducted for new generation interconnections or for planned major transmission system improvements that have regional impact. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and

cumbersome. Regarding R8, IID suggest the following languages: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Individual
Gregory Campoli
New York Independent System Operator
No
If the following recommended revisions are made to the requirements listed, subject to other unforeseen material changes, NYISO would no longer oppose the approval of this standard. Requirement R2.1.5 The current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already evaluated as part of category P6 in Table 1, additional studies should not be required, however spare equipment strategies could be ASSESSED in the context of the Planning Assessment. NYISO thus recommends this requirement be revised as follows: R 2.1.5 When an entity's spare equipment strategy could result in the unavailability of a major Transmission component that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed with due regard to categories P0, P1, and P2 identified in Table 1. Requirement R2.2 The language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study. NYISO requests that R2.2 and the sub-requirement be revised as follows: 2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies shall include: 2.2.1. Expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Requirement R8.1 There is an apparent open ended time frame afforded report recipients in their review of any Planning Assessment. This requirement should apply to only the most recent Planning Assessment. NYISO thus recommends the following language: 8.1. If a recipient of the most recent Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
No
Requirement 8 is an administrative burden that adds no value to reliability. Comments have been provided on several past drafts highlighting this effect. The revisions made to the VRF and VSL for Requirement 8 further exacerbate this burden. One could conclude from observation of the VSLs and VRFs, that Requirement 8 was the most important requirement of TPL-001-1. Many Planning Coordinators and Transmission Planners have stakeholder processes that govern participation and notification. Further, FERC Order 890 requires stakeholder participation and transparent processes.
Requirement R2.4.1 The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to the implementation of this requirement a modeling standard should exist that is specific to dynamic loads, including as assessment for the need for dynamic load models.
Group
Tri-State Generation and Transmission Assn., Inc.
Yes
In general, revisions are editorial and seem to have improved the overall document.
No
Many of the sub-requirements of R2 do not warrant high risk VRFs, yet violation of any R2 sub-requirement would result in a “High Risk Factor” violation assessment. We believe that having so many sub-requirements can result in inaccurate overall severity classification. For example, skipping one study defined in R2.1.2 (Planning Assessments) for a particular time frame or load level would probably not result in a direct actual degradation in system performance, but would still result in a High Violation Risk Factor.

R1.1 to “System models used for Steady State and Stability Analysis shall represent:” Much of what is in R1.1 is unnecessary for Short Circuit studies. In contrast, there are items not mentioned in R1.1 that are necessary for short circuit studies. R2.1.4 requires sensitivity analysis to study “a range of credible conditions that demonstrate a measurable change”. How will the required actions in R2.1.4 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? In R2.3, change the first sentence to read “The short circuit analysis portion of the Planning Assessment shall be conducted annually, using one of the cases described in 2.1.1, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6.” There appears to be no reason to perform short circuit studies for all three Near-Term Transmission Planning Horizon cases. R2.4.3 requires sensitivity analysis to study “a range of credible conditions that demonstrate a measurable change”. How will the required actions in R2.4.3 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? R2.7.1 remove the last bullet. We believe these programs are already factored into the load forecast, as they are associated with resource scheduling and planning load serving, and not transmission planning. In particular, DSM measures would fall under R2.4.1, and the term “new technologies, or other initiatives” The language of Requirement 3 unnecessarily repeats the language of R1 and R2. As now written, R3 states “For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.” R3 We recommend that the introductory language in Requirement R3 be changed to read “The studies in Requirement R2, Parts 2.1, and 2.2 shall be performed using models as defined in Requirement R1 in accordance with the following criteria.” We believe that Requirements 3.1 and 3.4 should be combined into R3.1, eliminating R3.4. It is redundant to have Requirement 3.1 say “perform R3.4”. We recommend that R3.4 be deleted and that R3.1 be replaced with: R3.1 Planning event studies shall be performed in accordance with “Table 1 – Steady State & Stability Performance Planning Events;” and shall be based on a supportable Contingency list. Comment: The content of 3.4.1 was intentionally omitted as it is redundant with R7. Also, the language “…more severe System impacts…” was intentionally omitted as it could be subject to a wide range of interpretations. Similarly, we recommend that R3.5 be deleted and that R3.2 be replaced with: R3.2 Extreme event studies shall be performed in accordance with “Table 1 – Steady State & Stability Extreme Events;” and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R3.2 language: Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Comment: As before, the language “…more severe System impacts…” was intentionally omitted as it could be subject to a wide range of interpretations. We recommend removing the second bullet of R3.3.1, “Tripping of Transmission elements where relay loadability limits are exceeded” for the following reasons: 1. There is currently no tool to model relay loadability characteristics in Steady State analysis. 2. Requirement R3.3.1 would require inclusion of relay models in modeling data that are not currently provided. MOD-012 does not require impedance or overcurrent relay models to be submitted. 3. In Requirement 3.3.1, the second bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. At best an individual point could be chosen to model relays based on a selected power factor. We recommend changing the opening text of Requirement R.3.3.2 to say “Simulate the expected automatic or manual operation…” Subrequirement R4.1.2 represents a tremendous increase in dynamic modeling complexity. Modeling relay action during apparent impedance swings would require inclusion of impedance relay models in modeling data that are not required to be submitted in MOD-012. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. We believe that Requirements 4.1 and 4.4 should be combined into R4.1 as shown below and R4.4 should be deleted. It is redundant to have Requirement 4.1 say “perform R4.4.” We recommend R4.1 language be revised to read as follows: R4.1 Planning event studies shall be performed in accordance with “Table 1 – Steady State & Stability Performance Planning Events;” and shall be based on a supportable Contingency list. Comment: The content of 4.4.1 should be omitted as it is redundant with R7. Also, the language “…more severe System impacts…” should be omitted as it could be subject to a wide range of interpretations. Similarly, R4.5 should be deleted and R4.2 should be replaced with: R4.2 Extreme event studies shall be performed in accordance with “Table 1 – Steady State & Stability Extreme Events;” and shall be based on a supportable Contingency list. We

recommend the following new requirement be inserted after the revised R4.2: Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the even(s) shall be conducted. Comment: As before, the language "…more severe System impacts…" was intentionally omitted as it could be subject to a wide range of interpretations. Clarify the first bullet in Requirement R4, part 4.3.1 by changing it to "High-speed (less than 1 second) reclosing, where the fault has cleared, and high-speed reclosing into the permanent fault , but in each case only if high-speed reclosing is utilized". In Requirement R4, part 4.3.1, third bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. Existing applications do have impedance relay models, but these models do not model many relay capabilities– for example, non-circular protection regions and load-encroachment. We recommend removing this bullet. The comment statement we made above referring to R4.1.2 also applies to R4.3.1. MOD-012 does not require reclosing relay model data to be submitted. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. Furthermore, there is not a standard built-in reclosing relay model in current stability simulation tools. Comments regarding Table 1- We assume the headnote i. to Table 1 - "The response of voltage sensitive Load…" - means that studies must not rely on end-user load tripping to meet the performance requirements defined in TPL-001-2 but that it should be modeled (when known) so that its occurrence would be evident. We don't see the need to apply Footnote 12 to only certain contingency categories or certain events in categories. Recommend putting the footnote in the column header just as with Footnotes 1, 2, 3, and 4. Recommend changing "utilized" in Measurement M3 to "performed." Recommend changing "utilized" in Measurement M4 to "performed." Modify Measurement M7 to "Each Planning Coordinator shall provide dated documentation on roles and responsibilities of its Transmission Planners, such as…" The deleted phrase, "in conjunction with each of its Transmission Planners," appears to be unnecessary.
Individual
Kirit Shah
Ameren
No
There were a number of comments made on the previous draft of TPL-001-2 for which there were few, if any, changes made to the latest draft of the standard. Specifically: Requirement R1 does not address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (possibly as an additional Requirement R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring. Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. In addition, it appears that only the peak load model in R2.4.1 is required to represent expected dynamic behavior of Load. Such load models, if adopted should represent dynamic behavior of the load for all dynamic studies.
No
The VRF for Requirement R8 should remain Low. There is no significant risk to the reliability of the BES if a Planning Assessment is not distributed to another entity, or if a documented response is not provided within 90 days of a request. The assignment of some VRFs are inconsistent with the importance of the requirements. R2 requires the development of an assessment and it is determined to have a high VRF. However, R3 and R4 require that studies be performed and these studies are determined to have a medium VRF. Performing the studies is essential to developing an assessment and more important to maintaining reliability. If the VRFs for R3 and R4 are correct, then the VRF for R2 should be no higher than medium. The VRF for R5 to develop a steady-state voltage criteria is determined to be medium. However, the VRF for R6 to develop instability criteria is determined to be low. If the VRF for R6 is correct, then the VRF for R5 should also be low.
With respect to Requirement R8, will posting the assessment to a secure web site meet the intent of the requirement? What are the Planning Assessment results identified in R8, and how are they different from the Planning Assessment? It appears that the language for R8 is inconsistent with the VSL for R8. The revised language for the VSL for R8 has removed the word "results". For

Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow, stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. The items listed as 4.1.1 through 4.1.3 are not requirements but are performance criteria and should be included in the Table 1 only, consistent with the other performance criteria. Overall, we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities. The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent.
Individual
Darryl Curtis
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Yes
Yes