NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Assess Transmission Future Needs (Project 2006-02)

Summary Consideration: Due to industry comments, the SDT has made a number of changes to the standard as shown below. In making these changes, the SDT has attempted to be responsive to the information provided in the initial ballot comments while continuing to be responsive to the FERC Order 693 directives. Please note that footnote 12 on non-consequential load loss is currently being utilized as a placeholder. The resolution of this issue will be provided in Project 2010-11. When that resolution is reached, the content will be copied to TPL-001-2.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

Requirement R1 - Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1.

Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Requirement R2, part 2.1 - The Near-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, as follows:

Requirement R2, part 2.1.4 - For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:

Requirement R2, part 2.1.5 - When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Requirement R2, part 2.4.1 - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Requirement R2, part 2.4.3 - For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:

Requirement R2, part 2.5 - The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

Requirement R3, part 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.
- Tripping of Transmission elements where relay loadability limits are exceeded.

Requirement R3, part 3.5 - 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. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Requirement R4, part 4.4 - 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 created of those Contingencies to be evaluated in Requirement R4, part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

Requirement R4, part 4.5 - 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 R4, part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Header note 'a': The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

Header note 'b': Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

Header note 'e': Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

Extreme event 2d. Loss of all generating units at a generating station.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

M6. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Kent Kujala</td><td>Detroit Edison Company</td><td>3</td><td>Abstain</td><td>Document is overly complex.</td></tr>
<tr><td>Daniel Herring</td><td>Detroit Edison Company</td><td>4</td><td>Abstain</td><td>I don't believe this end product from the consolidation of the TPL standards into one standard turned out the way the industry was hoping it would. This standard is long, complex, and difficult to follow.</td></tr>
<tr><td colspan="5">Response: The standard covers a number of complex issues and problems. The SDT has made every attempt to avoid unnecessary complexity. No change made.</td></tr>
<tr><td>Paul Rocha</td><td>CenterPoint Energy</td><td>1</td><td>Negative</td><td>CenterPoint Energy believes the proposed standard has strayed far from its original intent as indicated in the 2002 Version 1 SAR and that this proposed standard is now overly prescriptive.
CenterPoint Energy also will not support the proposed expansion of mandatory, auditable long term planning requirements beyond the requirements found in the existing TPL standards and the intent reflected in the 2002 version 1 SAR.
This concern is exacerbated by the expansion of stability studies and corrective action plan requirements applied to the long term planning horizon.</td></tr>
<tr><td colspan="5">Response: The SDT is providing clarity around all of the requirements consistent with the intent of the existing standards, the approved 2002 SAR, and the approved 2006 Supplemental SAR. No change made.</td></tr>
<tr><td>Gregory L. Pieper</td><td>Xcel Energy</td><td>1</td><td>Negative</td><td>No comment.</td></tr>
<tr><td colspan="5">Response: Without any specific comments to address, the SDT is unable to further address your concerns. No change made.</td></tr>
<tr><td>Charles Locke</td><td>Kansas City Power & Light Co.</td><td>3</td><td>Negative</td><td rowspan="2">The standards are overly prescriptive and will increase industry costs substantially without materially improving customer service or reliability, and I believe they go significantly beyond the original standard. If the reason for a new standard is to clarify interpretation problems with Table I performance, that should be addressed without all the additional requirements that are added in the new standard.</td></tr>
<tr><td>Thomas Saitta</td><td>Kansas City Power & Light Co.</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: The SDT is providing clarity around all of the requirements consistent with the intent of the existing standards. The SDT has attempted to balance</td></tr>
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Voter	Entity	Segment	Vote	Comment
reliability versus cost based on responses to comments in previous postings. No change made.				
Saurabh Saksena	National Grid	1	Affirmative	1. An annual study shouldn't be required for all areas. A documented assessment based on past studies should be adequate for some areas. 2. Years 5 and 10 need to be defined. It appears that the difference between Year One and year 5 is only 3 years. 3. In Table 1, event P5 is not clear enough to communicate that it doesn't include the failure of a single element such as a battery, which is included in the NERC glossary definition for a Protection System. 4. Part 2.7.2 should include Runback or tripping of HVDC in the list of possible actions. 5. Parts 2.1.4 & 2.4.3 should be revised from ' ... the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies ....' to ' ... the sensitivity analysis in the Planning Assessment must vary one or more of the following original conditions in the studies ....'. This will provide a reference similar to a Base Case definition as a reference for the sensitivities and will eliminate the implication of infinitely adding one more sensitivity to the list of sensitivities. 6. The implementation window for part 2.4.1needs to be increased from 24 to 36 months.
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	
Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and Part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance: **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:				

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2. The SDT believes that this concern is alleviated by the revised definition for Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

Then Year 5 would be four years after Year One and Year 10 would be nine years after Year One. Using the example in the definition of Year One, Year 5 would be the 12 month period that includes the forecasted peak load period of either 2016 or 2017, respectively, and Year 10 would be 2021 or 2022, respectively.

3. The SDT has changed the text for the P5 event and added a footnote 13 as a result of your (and others') comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

4. The SDT assumes that you meant Requirement R2, Part 2.7.1. As stated, the list is not all inconclusive but a list of possible actions. The SDT agrees that runback or tripping of HVDC would be allowable actions. No change made.

5. The SDT agrees that the current wording may be confusing and has made a change to promote clarity in this area.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:

> **Requirement R2, part 2.4.3 -** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:

6. The SDT has reviewed similar comments from earlier drafts and believes that the implementation timeframe for this item is appropriate. Without any further specific reasons, the SDT is unable to address your concerns. No change made.

Voter	Entity	Segment	Vote	Comment
Linda Brown	San Diego Gas & Electric	1	Affirmative	1. The new standard is supposed to be a performance based standard, but goes beyond performance by suggesting solutions (2.7.1). 2. The new standard is an overly wordy and poorly organized version of the original four TPLs. In order to understand a requirement, the reader must jump to different sections in the document. 3. The new standard is poorly written making it confusing. For example, R2.1.1 says "System peak Load for either Year One or year two, and for year five". I think it means, "study the system as it may exists 5 years from now and as it may exist either one year from now, or two years from now." 4. Section R2.1.4 of the new standard requires Real and Reactive forecasted load. This makes no sense. To my knowledge, no one forecasts reactive load. They assume a power factor and using the real power load and the assumed power factor, they calculate the reactive load. 5. The load modeling requirement may take some time to achieve. 6. It asks for sensitivities that assume generation that may never be built. 7. The Corrective Action Plan doesn't define who gets the plan. It just says to make one. 8. The new standard makes requirements out of practices. For example, section 3.3.3 requires relay loading actions to be part of the analysis. Any competent transmission planning engineer does this.

Response: 1. The proposed standard clarifies allowable solutions but doesn't mandate any particular solution without deviating from performance-based requirements. No change made.

2. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.

3. The SDT does not think the requirement is poorly worded nor are there other comments about this particular wording. Your assumption is correct but does not add any additional clarity. No change made.

4. Since the reactive Load is based on a forecast of the real Load, the SDT chose to characterize both real and reactive Loads as forecasts. No change made.

5. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. The SDT believes that 24 months is an adequate time period to accomplish this task. No change made.

6. The SDT has made a change to the requirements to promote clarity in this area. Generation is just one of the examples of what could be studied.

> **Requirement R2 -** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

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<tr><td colspan="5">
Requirement R2, part 2.1.4 - For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:
Requirement R2, part 2.4.3 - For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:
7. The Corrective Action Plan isn’t delivered separately as it is part of the Planning Assessment. Requirement R8 specifies availability of Planning Assessments. No change made.
8. The SDT wrote the requirements for the proposed standard based on reliability-based needs for a continent-wide standard for transmission planning purposes and have been vetted through multiple industry comment periods. Requirements are often based on existing practices. No change made.
</td></tr>
<tr><td>Dana Cabbell</td><td>Southern California Edison Co.</td><td>1</td><td>Affirmative</td><td>
1. We recommend moving the EHV and HV definition from the Performance Table footnote to “Definitions of Terms used in Standard” section.
2. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are:
o Application of consequential and non-consequential load and the EHV and HV voltage levels
o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system.”
3. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows:
o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:
o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:
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<tr><td></td><td></td><td></td><td></td><td>o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6.

The following studies are required in accordance with R4:

o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6</td></tr>
<tr><td colspan="5">Response: 1. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made.

2. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. Also, the SDT has clarified P5 in this revision.

2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.

2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made.

2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.</td></tr>
<tr><td>Thomas J. Bradish</td><td>RRI Energy</td><td>5</td><td>Affirmative</td><td rowspan="3">I support the WECC position paper on this subject. Namely:

1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard.

Some of the areas that require additional clarification are:

o Application of consequential and non-consequential load and the EHV and HV voltage levels

o Discussion on what is needed to study the various Planning Events. One example is P5, which</td></tr>
<tr><td>Scott Kinney</td><td>Avista Corp.</td><td>1</td><td>Affirmative</td></tr>
<tr><td>Dennis Malone</td><td>El Paso Electric Company</td><td>1</td><td>Affirmative</td></tr>
</table>

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Richard J. Padilla</td><td>Pacific Gas and Electric Company</td><td>5</td><td>Affirmative</td><td>involves "failure of a single protection system."

2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows:

o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4:

o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6</td></tr>
<tr><td colspan="5">Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff.

2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.

2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made.

2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.</td></tr>
<tr><td>Chifong L. Thomas</td><td>Pacific Gas and Electric Company</td><td>1</td><td>Affirmative</td><td>1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard.</td></tr>
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Voter	Entity	Segment	Vote	Comment
				Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified sub-requirements of R2 to inserting “in accordance with R3” or “in accordance with R4” to clarify references to R3 and R4, respectively, as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6 3. As proposed, Non-Consequential Load Loss is defined as "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment". As voltage at the fault goes to zero, and voltages in the parts of the system near the fault become very low, some voltage sensitive Loads may be tripped, and, as a result may not "ride through" the fault. Would this types of Load loss be covered under item (2), “the response of voltage sensitive Load” during the transient dynamic study, as long as the TP and PC model these Loads as connected to the system in the post-contingency steady state power flow representation?
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under				

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general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Yes, your assumptions are correct.				
Timothy VanBlaricom	California ISO	2	Affirmative	2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6: 2.2 The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6:
Response: 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Paul B. Johnson	American Electric Power	1	Affirmative	AEP appreciates the extensive efforts by the SDT to develop the version of this standard that is presently before the industry for ballot. The proposed version addresses much of the confusion that exists with the current standards that it will replace. The SDT should be commended for having gone to great lengths to explain the interpretation of this revised standard as part of its reply to industry comments. Adherence to this standard should result in a sufficiently reliable system by narrowing the broad interpretations that have been made of the requirements in the existing standards. AEP believes that the SDT has satisfied enough of FERC's concerns so that FERC will approve this standard if passed by the industry. Therefore, AEP supports approval of this standard. AEP would like to make a suggestion that any future revision of TPL-001-1 should place appropriate restrictions on the use of Special Protection Systems as a permanent solution in the Corrective Action Plan. While AEP recognizes that there are acceptable applications of SPS on a permanent basis, we are concerned that in highly interconnected portions of the grid the use of multiple SPS can cause complex interactions that would be difficult to predict and could lead to unintended consequences. AEP also recognizes that an SPS may be the only practical option on an interim basis.
Raj Rana	American Electric Power	3	Affirmative	
Brock Ondayko	AEP Service Corp.	5	Affirmative	
Edward P. Cox	AEP Marketing	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your response. The SDT will enter a comment in the official NERC issues database on your concern about permanent SPS solutions. That will assure that a future drafting team will address your concern.				
George R. Bartlett	Entergy Corporation	1	Affirmative	Entergy appreciates the work of the drafting team and recognizes the challenges associated with complexities of this effort. Entergy is voting “Affirmative” on the proposed standard but would appreciate the SDT consideration of the following comments in any further efforts to improve the standard: 1. The implementation plan is simply too aggressive. Locating and building transmission facilities continues to become more time consuming. Even lower voltage facilities can take 5 to 7 years to navigate through the various technical and regulatory challenges associated with building these facilities. Entergy would propose extending the implementation plan to 7 years for 230 kV and below, and 10 years for above 230 kV where transmission lines must be constructed. While the SDT has the intent that no penalties be imposed where facilities can not be constructed by the end of the implementation plan, we are concerned that ambiguity may exist may lead to issues should enforcement be left to interpret what is “beyond the control of the Transmission Planner or Planning Coordinator” in R2.7.3 2. 2. P5 in the new table is simply not defined to the extent that a consistent analysis method can be applied throughout the industry. While the process of identifying single points of failure will be time consuming and manpower intensive, it is feasible to complete. However, the consequences of those single points of failure can not be defined with consistency across the industry. Consequences of protection system failures are dependent on fault types, initial system conditions, and other factors which are not and can not be tracked in traditional planning tools. The ambiguities associated with P5 will almost certainly lead to additional standards needs and numerous requests for interpretation. Entergy would propose industry standardized proxies be allowed in lieu of detailed analysis of the interface between protection systems and the delivery aspects of the BES. Proxies could be developed to ensure the industry identifies and avoids events which have recently been associated with single points of failure in a protection system. 3. Entergy believes that more clarity is needed in R2.1.4 and R2.7 concerning sensitivity studies. The determination of when sensitivity study results should warrant mitigation should be left to the Transmission Planner and/or Planning Coordinator. The requirement to document the studies and their results will proved transparency and allow for transmission improvements through normal stakeholder and regulatory processes.

Voter	Entity	Segment	Vote	Comment
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). 3. The SDT did not receive any other comments in this regard and believes that the wording is clear. No change made.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy appreciates the dedication of the Assess Transmission and Future Needs Standards Drafting Team commends the group for their hard work to bring the proposed TPL-001-1 standard to industry for consideration. The TPL-001-1 standard provides greater compliance clarity than what presently exists in vague and open for interpretation TPL standards. The project appropriately consolidates six existing TPL standards into a single standard, while driving the industry to needed robust planning reviews. The team has carefully considered the industry feedback during the standards development and made many adjustments to better clarify the requirement language. The team is also commended for the improvements made to the Performance Table describing steady-state and stability performance expectations and creating the distinction between Planning Events and Extreme Events. FirstEnergy is voting to AFFIRM the standard and offers the following suggestions to the standards drafting team for areas of improvement and a more appropriate transition to the TPL-001-1 standard. 1) YearOne Definition: FirstEnergy requests that the team consider a change so that Year One is the planning window that begins 12-18 months from the "start" of the current calendar year, and not
Kevin Querry	FirstEnergy Solutions	3	Affirmative	
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	from the "end" of the calendar year. This change is needed so that minimal adjustments are needed to the ERAG MMWG model building process, which is the basis for planning models used by many within the Eastern Interconnection. The change would still meet the team's intent of requiring the industry to plan beyond current year load periods which are appropriately considered an operating timeframe in the context of TPL-001-1. If the team does not agree to this change for use in the TPL-001-1 standard, we ask the team to consider adding an Entity Variance that would permit the proposed change within the Eastern Interconnection. 2) Implementation Plan: The 60-month transition, as reflected in the team's Implementation Plan, may not be sufficient time for completion of new transmission facilities that may be needed as part of a Corrective Action Plan. The Implementation Plan calls for a 60-month period that is in parallel to the 24-month transition period for completing new model and study expectations per the TPL-001-1 standard. The proposed standard raises study expectations in a number of areas such as removing load shedding for n-1 conditions, more detailed load modeling regarding induction motor loads, developing and documenting transient voltage criterion, etc. FirstEnergy believes it is more appropriate for the 60-month transition for completed Corrective Action Plans to be sequential to the 24-month transitional items. It will take industry some time to transition to the new model and study expectations and industry should be allotted a full 60 months for the completion of major transmission infrastructure that may be included in Corrective Action Plans. 3) Two Near-Term Studies: FirstEnergy supports a need for "fresh" annual steady-state studies being completed for both the Near-Term and Long-Term planning horizons as reflected in requirement 2.1 which states "... be supported by the following annual current studies ...". However, we continue to stress that the need for two studies in the Near-Term horizon (requirement R2.1.1) creates unnecessary burden on industry resources, especially in light that sensitivity analyses are required for each study year. The focus should be that the Transmission Planner needs to cover the entire planning horizon through past and present (current annual) studies and allow the Transmission Planner more latitude to pick the current annual studies. A single present year study within the Near-term and Long-Term planning horizons, supplemented with past studies should be sufficient to effectively interpolate and extrapolate results to cover the entire planning horizon. To the extent a past study remains a qualified past study (as described in the standard in R2.6) we believe the transmission planner should still have discretion to continue to use those studies as their study time period moves forward.

Response: 1. Based on your comment and those of others, the SDT has revised the definition of Year One.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

3. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Requirement R2, part 2.1 - The Near-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, as follows:</td></tr>
<tr><td>William L. Thompson</td><td>Dominion Virginia Power</td><td>1</td><td>Affirmative</td><td rowspan="4">o Effective Date - For those raising the bar standards, corrective action plans must be implemented by 60 calendar months. We believe as we have commented previously that for new EHV facilities, this may be difficult to achieve. Our recommendation was to add an additional 24 months to that timeframe. However, they have added Requirement R2.7.3 which allows for situations out of our control to use non-consequential load loss to temporarily resolve violations until the corrective action plans are implemented. Although this does cover us as long as we have a legitimate reason, it does leave to the interpretation of the auditor that the reason is "valid". We therefore still believe more time should be allowed.

o Requirement R3.3.2 - Dominion does not agree that the low voltage ride through is a steady-state issue as included in requirement R3.3.2. We foresee demonstrating compliance for this requirement as a difficult if not impossible task hence subjecting the industry to undue non-compliance risk. Furthermore, we believe that low voltage ride through is a dynamic modeling issue covered in requirement R4.3.2.

o Assessment time and documentation - Although we do see the need and improvements in the standard, it is clear to Planning that more assessments and documentation will be the end result. It is difficult to determine how much time and resource requirements this will take until we begin implementing the standard. Planning does have a concern that additional resources will be required and have heard this from others in the industry.</td></tr>
<tr><td>Jalal (John) Babik</td><td>Dominion Resources, Inc.</td><td>3</td><td>Affirmative</td></tr>
<tr><td>Mike Garton</td><td>Dominion Resources, Inc.</td><td>5</td><td>Affirmative</td></tr>
<tr><td>Louis S Slade</td><td>Dominion Resources, Inc.</td><td>6</td><td>Affirmative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 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. • Tripping of Transmission elements where relay loadability limits are exceeded. The SDT is sensitive to this issue and that is why there is a staggered Implementation Plan. The timeframes are designed to allow entities time to catch up to the new requirements and were derived from a specific question asked of the industry.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	On page 3 of the Implementation Plan it is stated: "For 60 months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans…" It is unclear how this should be interpreted in those jurisdictions where no regulatory approval is required. For consistency, we recommend the following wording: "For 60 months after the first day of the first calendar quarter following applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, 60 months after the first day of the first calendar quarter following Board of Trustees adoption, Corrective Action Plans…"
Response: As pointed out in the comment, the wording on page 3 of the Implementation Plan should agree with the wording on page 2. The SDT has made this change. However, due to other comments, the 60 month period has been changed to 84 months. For 84 months after the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption, Corrective Action Plans applying to performance elements…				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Tom Bowe</td><td>PJM Interconnection, L.L.C.</td><td>2</td><td>Affirmative</td><td>PJM is supports the standard because it helps to remove the ambiguity in the existing TPL standards and it promotes actions that will result in an improvement in the reliability of the Bulk Electric System. PJM believes that the draft standard addresses the issues raised in the SAR and by FERC orders 672 and 693. The industry wide webinars conducted during the drafting process were particularly helpful in providing the industry with an additional vehicle to better understand the proposed modifications to the TPL standards and provided an additional avenue for industry feedback to the Standard Drafting Team.

While supportive of the standard PJM believes additional clarifying language should be added to the following requirements:

R 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

R 2.1.1. System peak Load for either Year One or year two, and for year five. It should be made clear the intent of the requirement for a “Year One or year two” assessment is to “dovetail” with the operational horizon in order to assess the steady state impact of changes from the system as planned. As currently written, the intent and required depth of the additional “Year One or year two” study is ambiguous.</td></tr>
<tr><td colspan="5">Response: Part 2.1 is already part of Requirement R2 so no additional reference is required. No change made.

Based on your comment and those of others, the SDT has revised the definition of Year One.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.</td></tr>
<tr><td>Ronald D. Schellberg</td><td>Idaho Power Company</td><td>1</td><td>Affirmative</td><td>Recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows:

o 2.1. ...by the following annual current studies in accordance with R3, ...

o 2.2. ...by the following annual current study in accordance with R3, ...

o 2.4. ... The following studies are required in accordance with R4:

o 2.5. ...and be supported in accordance with R4 by current or past studies ...</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Response: 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made.				
Jason L. Murray	Alberta Electric System Operator	2	Affirmative	While voting affirmative on this standard we agree with the following WECC comments: 1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6.

Voter	Entity	Segment	Vote	Comment
				The AESO would also like to add that due to provincial acts, regulations, policies and market structure in Alberta, the AESO and Alberta entities involved in the standards process will consider modifications to this standard when adopting it as an Alberta Reliability Standard. In particular we may need to consider rewording the requirements concerning the use of RAS as mitigation for single and multiple contingencies.
Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. 2.1 & 2.2 – The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. 2.4 – Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. 2.5 - The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Thank you for this information.				
Richard Jones	South Carolina Electric & Gas Co.	5	Negative	"SCE&G appreciates the efforts of the Standard Drafting Team and believes this version of the TPL standard has addressed most of the significant issues found in previous versions. However, SCE&G believes there are several significant issues that need modification or further explanation. 1. SCE&G agrees with other submitted comments that the requirement to complete new transmission construction to meet new performance requirements within 60 months is too short. SCE&G believes that 84 months is more reasonable. 2. SCE&G agrees with comments submitted by Duke Energy that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability and service quality. In many

Voter	Entity	Segment	Vote	Comment
Matt H Bullard	South Carolina Electric & Gas Co.	6	Negative	instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. 3. SCE&G believes there are still different interpretations of Consequential and Non-Consequential Load loss and how each should be applied or not applied. The Standard drafting team should provide several examples in its response to these comments showing how to apply and not apply Consequential and Non-Consequential Load Loss. Without clear examples, SCE&G believes many request for interpretation will be submitted to NERC by the industry.”
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others’) suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1, footnote b order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others’ concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT has clarified the issue of Non-Consequential Load Loss as shown above. Providing examples here of what is Non-Consequential Load Loss versus Consequential Load Loss would have no bearing. The words are what matter and the SDT feels that the clarification provided should alleviate your concern.				
Randi Woodward	Minnesota Power, Inc.	1	Negative	1. Requirement 2 - This requirement states that Stability analyses must be performed as part of the annual Planning Assessments. We would like to see the term "Stability analysis" more clearly defined as there are several different types of stability related analysis that can be performed for power systems including: transient stability, voltage stability and small signal stability. 2. Requirement 2.5 - This requirement states that "Stability analysis shall be assessed to address the impact of proposed generation additions or changes." We would like to see the term "proposed generation" more clearly defined. It is our opinion that only planned generation should be included in the Long-Term Transmission Planning Horizon assessment. In most generation queues there is a very large amount of proposed generation which would be impractical to study. These proposed generation additions are typically included in a System Impact Study which ultimately determines the transmission upgrades required for interconnection. 3. Requirement 2.1.5 - This requirement states that potential impact of the unavailability of major Transmission equipment be assessed annually for equipment (such as transformers) with long

Voter	Entity	Segment	Vote	Comment
				delivery lead times. We believe that it should be acceptable for a Transmission Owner to maintain a spare equipment plan that includes a reliability assessment. This plan would be reviewed and updated annually. We don't believe that a detailed assessment, as part of the Near-Term Transmission Planning Horizon assessment is warranted. 4. Requirement 4.1.2 - This requirement states that apparent impedance swings resulting from generator loss of synchronism shall not result in the tripping of any Transmission System elements. We believe that this requirement, as worded, precludes the use of transmission line out-of-step tripping relays to effectively island or isolate larger blocks of generation that have lost synchronism with the BES. 5. Requirement 4.3.3 - This requirement states that the assessments should simulate the impact of transient swings on Protection System operation. This would imply that detailed models of all transmission protection elements be included in the stability analysis. We believe that this is impractical due to the large number of relays that would need to be modeled. The standard should state that the use of a relay scanning model is an acceptable alternative to using detailed relay models. A scanning model typically monitors the apparent impedance for an established set of transmission lines and flags when the apparent impedances encroach on a classical 3-zone set of distance relay characteristics based on the monitored line impedance.

Response: 1. The SDT intended for the term Stability analysis to include system Stability and unit Stability analyses. These analyses could include all three aspects of Stability that you mentioned. It is left up to the judgment of the Planning Coordinator/Transmission Planner to decide which aspects of Stability may produce more severe results and therefore, must be analyzed. No change made.

2. Each Transmission Planner is governed by rules for when and how proposed generation units will be included in analyses. The current wording of the requirement is to allow for this degree of flexibility to remain part of the planning process. No change made.

3. The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

4. Requirement R4, part 4.1.2 – The SDT agrees that you can't use an out-of-step relay and that the situation you described is a system Stability issue and is considered an application for an SPS which is allowed by the standard. No change made.

5. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect

Voter	Entity	Segment	Vote	Comment
for each Contingency without operator intervention. The analyses shall include the impact of subsequent: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Robert Pellegrini	United Illuminating Co.	1	Negative	1. Section 2 of the standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This creates unnecessary study work and must be changed in order for UI to support the standard. 2. In Table 1 - Steady State & Stability Performance Planning Events, Category P5 wording for the EHV contingency continues to call for no loss of load in the event of the loss of a single protection system. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: “A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event”. It is UI's opinion that similar language excluding battery system failures should be incorporated into this requirement. 3. UI is concerned that the standard is completely silent regarding base case assumptions and stress levels (loads and interface transfers). The standard should provide some direction or statement of objective regarding base case development and sensitivity testing requirements. For example, the standard should include some statement(s) such as, “base cases(and/or) sensitivity testing must include consideration of reasonable unplanned and planned generation outages”. On the other hand UI does not suggest trying to precisely describe the number of generators that should be assumed out of service in this national standard.
Response: 1. The intent of the SDT wasn’t that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2 -** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-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, as follows:				

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<tr><td colspan="5">2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

3. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.</td></tr>
<tr><td>Dan R. Schoenecker</td><td>Midwest Reliability Organization</td><td>10</td><td>Negative</td><td>1. Section 2.5 proposed generation is too broad and overly inclusive. It should be replaced with planned or committed.

2. We have a concern that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. We are aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous and maybe problematic for compliance.

3. We believe the spare equipment language doesn’t belong in the standard. Whether a Transmission Owner has spare equipment is a risk for that Transmission Owner to evaluate and then take responsibility for the decision. For the Planning Coordinator, inclusion of the spare equipment language would mean that for each Transmission Owner’s piece of equipment that cannot be replaced within one year 3 more base cases would need to be run for each season and load level, which may lead to an excessive amount of base case development with little resulting benefit to reliability.</td></tr>
<tr><td colspan="5">**Response**: 1. Each Transmission Planner is governed by rules for when and how proposed generation units will be included in analyses. The current wording of the requirement is to allow for this degree of flexibility to remain part of the planning process. No change made.

2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others’) suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

3. The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a</td></tr>
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Voter	Entity	Segment	Vote	Comment
lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Roger C Zaklukiewicz	Roger C Zaklukiewicz	8	Negative	1. There does not appear to be a resolution to the issue of BES definition 2. A concern that too many years are required to be studied annually. Are this many studies required especially if there are no substantial transmission infrastructure additions or modifications and virtually no generation resource additions or retirements. 3. At state siting hearings, the Standard has to address the appropriate use of 90/10 or 50/50 peak load forecasts, the requirement to maintain established intra- and inter-transfer limit levels under stressed conditions. Also, more specific requirements regarding appropriate generation dispatches for area studies and large area or regional load flow and voltage studies. 4. Re-think the need or justification for modeling loads dynamically. Simulations of actual system disturbances have represented past actual system responses with a high degree of accuracy.
Response: 1. The SDT does not believe that it needs to define BES. In their March 18th orders, FERC suggested a continent-wide definition of BES. No change made. 2. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-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, as follows: 3. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made. 4. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.				

Voter	Entity	Segment	Vote	Comment
James Tucker	Deseret Power	1	Negative	1. While draft 5 of this proposed standard is a substantial improvement over the previous drafts and the existing TPL standards, there are still areas where additional clarity is needed. We believe that a workshop, after FERC approval of the standard, where issues can be discussed and clarified will go a long way towards smooth implementation of this proposed standard. Some of the areas that require additional clarification are: o Application of consequential and non-consequential load and the EHV and HV voltage levels o Discussion on what is needed to study the various Planning Events. One example is P5, which involves "failure of a single protection system." 2. We recommend the following slight modification to the specified subrequirements of R2 to include clarifying references to R3 and R4 as follows: o 2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.2. The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study in accordance with R3, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: o 2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part 2.6. The following studies are required in accordance with R4: o 2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported in accordance with R4 by current or past studies as qualified in Requirement R2, part 2.6 3. Table 1-P5 Multiple Contingencies (Fault plus Protection System failure to operate) Normal System. There is a significant change in the system normal performance required for EHV systems from the current performance required in TPL-003 (Category C). This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. As written the standard essentially now requires Category B performance rather than Category C performance for multiple contingencies. It is Deseret's opinion

Voter	Entity	Segment	Vote	Comment
				that loss of Non-Consequential load or firm Demand should be allowed for the rare event involving multiple contingencies stated in P5 as long at the load or firm Demand loss is contained and controlled in the local load service area and the event does not impact other interconnected utilities or their loads. 4) Table 1 - Steady State & Stability Performance Planning Events Category P5 (Multiple Contingency (Fault plus Protection System failure to operate). Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. As the draft standard is presently written it appears that multiple protection system failures are not included in this part or any part of the draft TPL-001-1 standard. As written, it is Deseret's view that any multiple protection system failure would be categorized as an Extreme Event under the draft TPL-001-1 standard. Deseret contends that the many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. In fact, there is currently a proposed standard going through the NERC standards development process which goal is exactly that. If the standards drafting team intends to require responsible entities to have 100% redundant protection systems on all of its BES facilities, Deseret contends that this fact should be stated up front in the standard so that all interested parties may become aware of this requirement and provide informed comment. Deseret believes that it is appropriate to wait until the current protection system redundancy standard under development proceeds through the SAR process and approval system, given that this in an important generic issue that affects the entire industry. Notwithstanding the inappropriateness of raising the protection system issue in the context of a planning standard, Deseret believes that any planning requirement that includes the failure of a single protection system that results in delayed fault clearing must have a very clear definition of the terms "single protection system" and "delayed fault clearing" in or for entities to determine what compliance with the standard requires. The draft TPL-001-1 standard does not have clear definitions of these terms, leaving room for considerable latitude for interpretation by various responsible entities, auditors, and compliance enforcement authorities. Clear, specific, and technically defensible language is needed for these terms.

Response: 1. The SDT has held several webinars on this project and may well hold another before the project is complete. In addition, the SDT has performed numerous outreach activities to regional entities, sub-committees, etc., on the details of the standard. The project has been presented several times at the NERC Standards Workshops. Once the standard is approved by FERC, the SDT ceases to exist. Therefore, any activities subsequent to that approval would be under

Voter	Entity	Segment	Vote	Comment
general NERC jurisdiction. The SDT suggests that you broach this idea with NERC staff. The SDT feels that the linkage between requirements is properly cited in Requirement R3 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. Part 2.4 is already part of Requirement R2 so no additional reference is required. No change made. The SDT feels that the linkage between requirements is properly cited in Requirement R4 going back to Requirement R2 and the additional language suggested is not necessary and does not add clarity. No change made. The SDT agrees that the bar has been raised for the EHV system in that no planned Load shedding (Non-Consequential Load Loss) is permitted for the P5 condition beyond Protection System clearing that responds to the studied P5 event. All Load removed by the Protection System isolating the Fault is Consequential Load Loss for the event. The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees with this premise and is attempting to do this in a reasonable fashion. No change made. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Bernard Pelletier	Hydro-Quebec TransEnergie	1	Negative	The reason for the No vote cast by HQT is that HQT still believe that the EHV and HV threshold defined as a fixed voltage (300 kV) on footnote 3 of Table 1 is too prescriptive, and unnecessary, for NPCC Members using a performance base methodology to determine elements of the BPS. HQT believes that if the 300 kV threshold was introduced as a necessity to reduce the BES portion of the system subject to the Standard in some region with a 100 kV bright line definition of BES so that entities in these regions do not incur prohibitive spending to respect this Standard, there should also be a way to accommodate NPCC Member's use of a performance methodology to determine on which elements to apply the Standards without having entities guessing the way Compliance will be implemented for this Standard in regard to specific voltage threshold. For HQT's system, EHV should correspond to 735 kV since more than half of our 315 kV substations directly supply load. The SDT gave this answer as the rational for choosing the 300 kV threshold when they replied to HQT concerns about the EHV voltage definition as 300 kV and over, in the first posting of the Standard : Â« Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers... Obviously the intent of the SDT when choosing a 300 kV threshold do not correspond to the reality of HQTs system characteristic. HQT agrees with the intent of the SDT to raise the bar in that important Standard but disagree with having to systematically apply the

Voter	Entity	Segment	Vote	Comment
				Standard to all 300 kV and above system. One way to clarify the Standard would be to mentioned in the footnote 3 that :`` In the region where there is a performance base methodology to determine BES element, these BES elements would be subject to the Standard; in other region, the 300 kV threshold would apply.
Response: This standard applies to the BES. If there are areas of your system that are not BES, then the standard doesn't apply to them. This would be true even if those elements are above 300 kV. No change made.				
Donald Gilbert	JEA	5	Negative	Although this proposed standard places additional burden of proof upon JEA's Transmission Planning process, JEA finds the overall direction of the standard requirements prudent. JEA appreciates the allowance of Non-Consequential Load Loss afforded in provision 2.7.3 where documented circumstances outside the control of the TP or PC suffice; however, JEA is concerned that there are some limited prudent cases where consumers, local jurisdictions, and state jurisdictions may find it prudent to plan on some Non-Consequential Load Loss in order to defer building transmission infrastructure (just for the purpose to serve speculative load growth) for the overall benefit of the consumer. Therefore, concerning the prohibition of Non-Consequential Load Loss, JEA proposes the addition to the standard that allows the use of Non-Consequential Load Loss for local area load for planning events where it is not presently allowed. In Â¶1794 of Order 693, FERC stated "Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator." Clearly, FERC did not direct NERC to eliminate "all" use of Non-Consequential Load Loss for single contingencies, but rather stated that its use should be "considered through the Reliability Standards development process". Therefore, the SDT should define "local area" where load loss is allowed and either set limits on how much load can be lost or a reporting requirement to ensure transparency concerning this planning practice. I propose that the standard should define "local area" as the load that is located on a single loop between two BES sources and limit the Non-Consequential Load Loss to the amount of Consequential Load Loss that would occur if the networked loop of load serving stations were sectionalized such that the loop operated as two radial circuits. The Standard could further require the TP or PC to document the results of both simulations with and without the sectionalization of the loop comparing the levels of Non-Consequential Load Loss to the level of Consequential load loss." This approach would clearly not be "a least common denominator approach", but rather a practical manner to allow the balance between transmission expansion costs and the limited risk to the local load within an area.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Kirit S. Shah	Ameren Services	1	Negative	Ameren appreciates the diligence and dedication of the Standard Drafting Team and commends the group for their hard work to bring the proposed standard TPL-001-1 to this level. We have seen considerable improvements to the proposed standard from earlier versions and note the positive changes to many of the requirements. We also recognize that the overall language of the standard has improved to enhance its readability and the language and format of the Tables now provides a clear understanding of acceptable System performance for the various Planning Events. However, inasmuch as the proposed Standard has improved, we cannot support the approval of this document at this time. 1. We disagree with the proposed definition of Year One. We believe that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from the end of the calendar year. We believe that following this modification to the definition would require minimal adjustments to the ERAG MMWG model building process, which we all use as the basis for our planning models. Following the proposed definition would require additional models to be built by the MMWG or lead to holes in the model building effort for both the operating and planning horizons. 2. We do not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the auditor whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. 3. We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. Although the proposed standard offers that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable (to relieve the burden of trying to develop specific induction motor load representation at each load bus), we believe that the modeled System response will be considerably different compared to the actual System response in some parts of the System which will open up the industry to additional scrutiny, such as the Compliance Inquiry (CIQ) and/or Compliance Violation Investigation (CVI). 4. We do not agree that low voltage ride-through is a steady-state issue as included in requirement

Voter	Entity	Segment	Vote	Comment
				R3.3.2. We believe that low voltage ride-through is a dynamic modeling issue as correctly included in requirement R4.3.2. 5. We have concerns that the dynamics models cannot support the additional data requirements to include actual impedance relay models for all transmission facilities to meet the requirements of R4.1.2 and R4.3.3. In an attempt to relieve our concerns, the SERC presenters indicated that generic PSS/E impedance relay models could be included in the dynamics models. However, we also have concerns for using generic PSS/E impedance relay models as the actual impedance relays may be set differently than the generic PSS/E relay models which will open up the industry to additional scrutiny, such as the Compliance Inquiry (CIQ) and/or Compliance Violation Investigation (CVI).

Response: 1. Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

2. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

3. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. The SDT believes that 24 months is an adequate time period to accomplish this task. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.

4. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement.

> **Requirement R3, part 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.
> - Tripping of Transmission elements where relay loadability limits are exceeded.

Voter	Entity	Segment	Vote	Comment
5. 4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** 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: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Robert D Smith	Arizona Public Service Co.	1	Negative	APS proposes that the standard allows the use of Non-Consequential Load Loss for local area load for P1 events. The current requirements may pose significant burden without appropriate benefits. As currently written APS does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the audit whether the appropriate actions are being taken to resolve the issue. APS proposes that the requirement be changed to 84 months.
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
John Tolo	Tucson Electric Power Co.	1	Negative	As currently written it is believed that 60 months is not a reasonable time period to build transmission facilities to meet the new performance requirements. Regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Category P2 requires responsible entities to study the opening of a line section without a fault. The

Voter	Entity	Segment	Vote	Comment
				standard as written states that the opening of this line section will not result in consequential load loss and no voltage or thermal violations will occur on the BES. This requirement should not be applicable to all HV facilities. From a reliability perspective, a more effective and efficient method would be a bifurcated functional requirement rather than a voltage requirement. This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. Many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. The standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT believes that the addition of footnote 12 (when it is finalized) will address your concern.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall

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				be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
Brandy A Dunn	Western Area Power Administration	1	Negative	As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment strategy and lead times and inclusion in the “Planning Assessment”. The standard in this section is not a performance based requirement but an activity based requirement as currently stated under R2 2.1.5. We recommend that the standard be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	We believe that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Yes, it may be possible to arrange an agreement with a neighboring entity for use of their spare, but that assumes that the neighboring entity's transformer specifications are similar enough for use as a spare, which may not be the case. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity’s spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages in requirement 2.1.5, in other words, if an entity has no plans for a long term outage of a transformer, it should be excluded from the assessment of 2.1.5. Such a condition would allow an entity to assess things like gas in oil analysis to predict when a long term outage might be planned, and the flexibility between start and end dates of that planned outage.
Bruce Merrill	Lincoln Electric System	3	Negative	Requirement 2.1.5 should only address known planned outages of major Transmission equipment that has a lead time of one year or more. As currently drafted requirement 2.1.5 does not specify whether it includes both forced outages and planned outages. Requirement 2.1.5 also does not specify that system adjustments are allowed since adjustments are not allowed in categories P0, P1, and P2. Without system adjustments the requirement 2.1.5 would always produce more severe System impacts than the categories P0, P1, and P2 in Table 1. Allowing System adjustments would make requirement 2.1.5 (P1) match category P6, yet requirement 2.1.5 (P2) would still result in more
Dennis Florom	Lincoln Electric System	5	Negative	

Voter	Entity	Segment	Vote	Comment
Eric Ruskamp	Lincoln Electric System	6	Negative	severe System impacts than currently contemplated in the TPL-001-1 Standard. It appears that requirement 2.1.5 would greatly increase the study work by requiring a new base case for each unique Transmission equipment and repeating the associated contingency analysis. Would Correction Action Plans be required for requirement 2.1.5, whereas, they do not need to be developed solely to meet the performance requirements for a single sensitivity?
Response: The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.				
Elizabeth Howell	ITC Transmission	1	Negative	As written, the balloted standard is a significant advancement over the past planning standards. It raises the bar for the EHV system (>300kV) and is a significant step forward toward the desired improvement in the North American electric grid. The detailed requirements along with the Table 1 performance expectations for Planning Events should result in Corrective Action Plans that improve the electric grid in measurable ways. The additional specifications to insure that load will not be lost, intentionally or otherwise, during relatively routine system outages reinforces the value of reliability standards. While ITC recognizes the significant improvement in the Planning Standard and applauds the Standard Drafting Team (SDT) for constructing this new document, we believe minor changes are still needed to provide clarity to the standard to avoid possible miss-interpretation of the intent of the SDT during compliance audits and the potential for unnecessary duplication of study effort in areas if differences between the studies conditions are relatively small. Minimally, ITC feels additional guidelines need to be supplied for some of the decisions left to engineering judgment, such as in R2.5 where it is clear as to the need for studies of "new" generation, no "minimum" size is indicated. Additional guidelines should be added to the standard and the Reliability Standard Audit Worksheet (RSAW) should be completed prior to balloting the standard. ITC is concerned about the mandatory need for the three distinct studies as required in R2.1 and R2.2 if the differences between the prevalent conditions are projected to be small. For example, if a systems load changes are insignificant between years 1 or 2 and year 5, and other conditions changes such as generation additions, power flow patterns and other are small for the system under study. The same issue may exist between year 5 and years 6 through 10 Under such conditions these studies may not be prudent and necessary to thoroughly evaluate the systems performance. ITC

Voter	Entity	Segment	Vote	Comment
				agrees with the SDT that the three studies make sense and are prudent when a system's conditions are changing. A review of how this section in the standard might be warranted. While a spare equipment strategy is a good idea, R2.1.5, the requirement should be clear to avoid compliance violations for the implications of a major piece of equipment failure with or without spare equipment. Until this is clearer for both Planners and auditors or an RSAW is available, there is a greater likelihood for compliance issues. ITC also has concerns regarding requirements R3.3.2 and R4.3.2 regarding Low Voltage Ride Through (LVRT). Both require tripping of generators when "voltages are less than known or assumed generator low voltage ride through capability". This means the planner either knows the limit or assumes one. For ITC, we only trip for "known" limits, such as those for wind generators. Our policy is to not "assume" LVRT. A concern is if a LVRT is not assumed for all plants will a transmission company be found not compliant. This should be made clearer either in the standard or in an RSAW. For these reasons, ITC is voting no at this time. ITC would like to see the SDT add clarity to the sections identified above or develop a Reliability Standard Audit Worksheet to accompany the standard being ballotted. Please feel free to contact us if you have questions regarding our comments.

Response: The SDT has clarified the requirement wording to address your concern.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

> **Requirement R2, part 2.1 -** The Near-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, as follows:

The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">unavailability of the long lead time equipment

The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be considered in the steady-state analysis. The SDT has clarified the wording of the requirement.

Requirement R3, part 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.
Tripping of Transmission elements where relay loadability limits are exceeded.
The development of an RSAW is more properly the purview of the Compliance Dept. No change made.</td></tr>
<tr><td>Jason Shaver</td><td>American Transmission Company, LLC</td><td>1</td><td>Negative</td><td rowspan="2">ATC believes that the Standard is moving in the right direction, but has identified the following concern which is preventing us from voting “affirmative”.

Our concern is that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years.

ATC is aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous. Clarity needed (R 2.7.3): 1) An auditor could identify many things that could reasonably be within the “control” of a TP or PC but are not covered by NERC standards or a TP / PC’s process, procedures or criteria. This wide area of discretion leaves entities open to possible non-compliance violation based on an auditor’s perception of what they believe should be in the TP / PC’s control. 2) In addition, we believe that the concept of “control” must be limited to an entities compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words entities must be allowed the ability identify situation which fall under its “control” as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its Transmission Planner or Planning Coordinator functions. . Suggested footnote: A TP or PC is in compliance with this requirement if the situation being documented is not covered in its internal processes, procedures or criteria required for NERC/Regional compliance obligations assigned to the TP or PC functions. Transmission Planners and Planning Coordinators are responsible for the identification of a CAP but it is the Transmission Owner that is ultimately responsible for implementing the CAP.</td></tr>
<tr><td>Gregory J Le Grave</td><td>Wisconsin Public Service Corp.</td><td>3</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				Additional areas of concern: ATC requested that the SDT re-examine the following concerns which we have been previously identified: 1. R1.1.2 "known outages of at least six months in duration" - The present wording in inconsistent between R1.1.2 and R2.1.3. We suggest that this requirement be removed because the “known outage(s)” are only to be included in the models when P1 events are simulated, as specified in R2.1.3. We suggest that the intent of this requirement can be more simply handled by stating in R2.1.3 that “known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur”. 2. R2.1.4 & R2.4.3 "range of credible conditions that demonstrate a measurable change in performance" - We suggest that the terms "credible" and "measurable" be define or use words that more definitively describe the requirement. 3. Table 1 - Requirements are “buried” in the Performance Table, rather than being included in the Requirement Section - a. Add R2.7.5 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We propose the addition of the following bullet item to R2.7.5. It could read, “Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings.” Note “e” in the Planning Events, Steady State & Stability section is stated in the form of a Requirement (e.g. use the verb “shall”), but all requirements should be included in the Requirements section and not introduced (and basically hidden) in the performance notes of Table 1. [After bullet item #7 is added, Note “e” under “Steady State & Stability section of Table 1 should refer to R2.7.5] b. Add R3.3.5 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We suggest the addition of R3.3.5. The text of R3.3.5 should read, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” Presently, Note “a” and “b” under “Steady State Only” at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, “shall”) and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note “a” should be revised and refer to R3.3.5.] c. Add R3.6 - We believe that all requirements should appear in the Requirements section and not be "buried" in the performance tables. We suggest the addition of R3.3.6. The text of R3.3.6 should read, “The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements.” because Note “d” under “Steady State Only” at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, “shall”) and all Requirements should be explicitly

Voter	Entity	Segment	Vote	Comment
				stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note “d” should be revised to refer to R3.3.6.] 4. R2.7.2 - "include actions to resolve performance deficiencies identified in multiple sensitivity studies" - We do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the interpretation of multiple studies - more than one or a majority of the number that were studied? 5. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact still be required?

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others’) suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

The SDT believes the existing wording is clear and that the suggested wording is equivalent without providing any additional clarity. No change made.

Requirement R2, part 2.1.4 is part of Requirement R2 which mandates that an entity must document all assumptions utilized in the Planning Assessment. No change made.

The suggested change would move header note ‘e to new Requirement R2, part 2.7.5 on the premise that it is a buried requirement. The phrasing of header note ‘e’ does not indicate that it is a mandatory requirement. It is a statement of allowed actions consistent with other notes. No change made.

The SDT does not believe that the items mentioned are buried requirements; rather they are statements of system performance that are better placed in the performance table. Requirements R3 & R4 specifically refer to the table which makes the table part and parcel of the requirements. No change made.

The SDT believes that it is more effective to state this as a header note instead of repeating it multiple times throughout the table. It is not a buried requirement but a description of what is utilized in the simulation. No change made.

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made. The requirement states that an entity must supply the rationale for those events selected so the SDT believes that your concern has already been addressed. It provides the necessary guidance while allowing needed flexibility and not being overly prescriptive. No change made.				
Larry E Watt	Lakeland Electric	1	Negative	Below are some proposed changes and requests for clarification concerning the new TPL-001-1 standard. R2.6.2 The phrase “material changes” is not explicitly defined, and it is unclear what changes constitute a “material” change. It is asked that more precise wording or a definition of the word “material change” be provided. R3.3.2 The words “...known or assumed minimum generator steady state or ride through voltage limitations...” could be (and were) read as a series, with “known”, “assumed minimum generator steady state”, and “ride through voltage limitations” interpreted as three items in the series. For clarity, it is suggested that the standard be rewritten as such: Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than the known or assumed minimum generator steady state, or the known or assumed ride through voltage limitations. Include in the assessment any assumptions made. Here, the comma separates the two items in the series, with the words “known” and “assumed” modifying each of the items. R4.3.2 Following the changes made to requirement 3.3.2, it is suggested that requirement 4.3.2 be changed to the following: Trip generators where simulations show generator bus voltages or high side of the Generation Step Up (GSU) transformer voltages are less than the known or assumed minimum generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3 An issue has been raised as to whether the word “simulate” denotes the modeling of all relays that protect transmission lines and transformers within a power flow/transiant simulator. It is suggested that this word be changed to “assess,” to clarify that this requirement does not compel the Planning Coordinator and Transmission Planner to conduct PSS/E simulations to study the above conditions. The revised requirement can read: Assess the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.4.1 There are two concerns with this requirement. The first is that this requirement makes no provision for the adjacent Planning Coordinator (PC) and Transmission Planner (TP) with a System Contingency to notify the PC and TP of the impacted System. Instead, the responsibility falls on the

Voter	Entity	Segment	Vote	Comment
				PC and TP of the impacted System to confer with each of their adjacent PCs and TPs to verify if a contingency on an adjacent System impacts the formers System. Or, it can cause the PC and TP to perform exhaustive contingency analyses (P0-P7) on all adjacent systems to determine which contingency/contingencies can impact their system to include them in their Contingency list. The second is that the term “impact” is not defined. A concern is should a Contingency cause a line on an adjacent System to load from 99% to 101% of its SOL rating, does this 2% constitute an “impact”? Conversely, would a Contingency that causes a significant increase to an adjacent System’s line of 5% or more, without violating that line’s SOL rating, be considered as having “impacted” the adjacent System? The proposed change to this requirement is: Adjacent Planning Coordinators and adjacent Transmission Planners will coordinate the identification of those Contingencies within their Systems and determine which, if any, impact the adjacent System. Those identified Contingencies may then be added to the adjacent Planning Coordinators and Transmission Planners’ Contingency List. With this change, PCs and TPs of both Systems are responsible for coordinating their efforts, and the definition of “impact” is left to the coordinating PCs and TPs to decide. R8 It is unclear whether the adjacent Planning Coordinators and adjacent Transmission Planners must submit a written request for the information, or if the written request applies only to the functional entity that has a reliability related need. If the adjacent Planning Coordinators and adjacent Transmission Planners do not need to submit a written request, should the Planning Assessment be sent to them automatically?

Response: Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as stated in the requirement. No change made.

The SDT does not see any real difference in the suggested wording from what is already there. No change made.

The SDT does not see any real difference in the suggested wording from what is already there. No change made.

The SDT has clarified the requirement to address your concerns.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual

Voter	Entity	Segment	Vote	Comment
relay models. Since the requirement is written for each Planning Coordinator and Transmission Planner, it covers the exchange of information on critical Contingencies and their impacts among all Planning Coordinators and Transmission Planners and thus distributes the responsibility and work load. No change made. The SDT does not see any real difference in the suggested wording from what is already there. No change made. The requirement clearly states that the entity must have a reliability-based need for the information so that unauthorized requests won't be made and the request for the information must be in writing. No change made.				
Eric Egge	Black Hills Corp	1	Negative	BHC does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line varies significantly in regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the audit whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the "Planning Assessment". The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. PacifiCorp recommends that the standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. Requirement R2, part 2.7.3 requires an entity to document their actions. Therefore, it is up to the entity to ensure that the documentation sufficiently explains their position. No change made. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall				

Voter	Entity	Segment	Vote	Comment
				be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
Janelle Marriott	Tri-State G & T Association Inc.	3	Negative	Definitions section- Add a definition to this standard, which would revise the definition of "Stability" in the NERC glossary to read: "Stability: Unless qualified specifically as Voltage Stability, the term Stability shall mean the ability of system generators to maintain angular equilibrium, also known as Dynamic stability." Definitions section- The definition for Year One is vague. If the definition is intended to capture both a summer and winter season and is necessary to provide a clear starting point for the planning horizon, then this should be stated explicitly in the definition. We recommend inserting the phrase "12-month" before the phrase "planning window" R2.1 The word "current" can mean either "electrical current" - a physical measure of electron movement, or "at the present time" - most recent or up-to-date. If you must use the term "current" in R2.1, say "current annual studies" rather than "annual current studies". R2.1.4 Part 2.1.4 should be removed from the requirement. The benefits of requiring one or more of these is unclear. Which of the listed conditions does an entity choose? There are no criteria for selection of one of the listed sensitivity topics as most-significant to a particular system. It is not apparent how particular sensitivities would increase BES reliability. If this part is not deleted, we recommend removing the phrase "not already included in the studies". Also, this requirement must state how one could determine validity of chosen sensitivity conditions. R2.1.5 We suggest adding the word "individually" to the end of the first sentence of part R2.1.5: "impact of this possible unavailability on System performance shall be assessed individually." In R2.4.1, it is left to the utility what level of load modeling detail is used. This is good because it gives the utility flexibility to select and use appropriate models. However, is it not clear what behavior of induction motors is targeted here. We recommend deleting the phrase "considering the behavior of induction motor loads", or else please specify what behavior is of concern. Part 2.4.3 should be removed from the requirement. As commented in our response to part 2.1.4, the benefit of requiring one or more of these is unclear - which of the listed conditions does an entity choose? There are no criteria for selection of one of the listed sensitivity topics as most-significant to a particular system. It is not apparent how this would increase BES reliability. If this part is not deleted, we recommend removing the phrase "not already included in the studies". Also, this requirement must state how one could determine validity of chosen sensitivity conditions. R2.6.2 We suggest that 2.6.2 be modified to read: "the System represented in the study has not
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	

Voter	Entity	Segment	Vote	Comment
				materially changed, or a technical rationale can be given that the changes do not impact performance in the study area." If 2.1.4 and 2.4.3 are removed as we suggest, then this sentence in part 2.7 should be removed: "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirement R2, parts 2.1.4 and 2.4.3." In part 2.7.1, remove the second sentence and all bullets. These are not measurable performance criteria. R3.5 asks for evaluation of actions designed to reduce the likelihood of potential cascading caused by extreme events, but 1) does not require documentation of results, and 2) does not require that the evaluation show that proposed actions would affect or limit cascading. R4.1 Insert "compliance with" in R4.1 text, which will then read "based on the Contingency list created in compliance with Requirement R4, part 4.4." There is no list in part 4.4. Part 4.4 requires a list of more severe contingencies (Table 1 planning events) to be created. R4.1.2 is unrealistic. Utilities implement out-of-step tripping schemes to limit the extent of impacts of such events that cause out-of-step conditions. Some of these occurrences can be mitigated better by tripping transmission elements and not generation. The decision to trip either transmission or generation should not be predetermined in the standard. We recommend that part 4.1.2 be reworked. R4.1.3 Does this preclude the regional reliability organization from choosing to establish damping criteria at some time in the future? R4.3.1 It is unclear whether this refers to the possibility of reclosing system failure, or the impacts of reclosing into a still-faulted system. R4.3.2 This is an admirable goal, and we applaud the SDT's vision. However, modeling all Protection Systems may be beyond the capabilities of presently used dynamic modeling tools. The number of impedance and overcurrent relays that would need to be included for lines and transformers would likely overwhelm these programs. We are concerned that the programs in use may not have the capability to model important relay characteristics such as load encroachment or out-of-step operating characteristics. R4.3.4 The phrase "of electrical system quantities" is unclear and can be removed without changing the intent of the requirement. R6 Remove the "for conditions such as ..." list.

Voter	Entity	Segment	Vote	Comment
				Does Table 1, Category P5, require consideration of clearing from all remote terminals and evaluating those time delays assuming no tripping is available locally? Table 1 Extreme Events List- In the Stability section of the Table 1 Extreme Events List, use the term Dynamic Stability, not just Stability - or insert a revised Stability definition as noted above. M8, part 1.4 Simplify by changing "current, in force documentation" to "operative documentation". "Current" is redundant with "in force". Table 1 - Headnotes to Planning Events o Table 1, Headnote b - Delete “or extreme” since this headnote is for Planning Events. o Table 1, Headnote e - You may omit the phrase “For all planning events,” since this headnote is for Planning Events. o Table 1, Headnote i - It is unclear what is meant by “end-user equipment associated with an event”. o Table 1, Headnote h -We suggest this be moved to a footnote for P0: “Planning Event Category P0 is applicable to steady state only. No Dynamic Stability Analysis is required.” o Headnote j - It is not clear why this falls under “Stability Only”, and suggest that “dynamic stability” be included with headnote “a” Table 1 - Footnotes o Table 1, Footnote 2 - We suggest this footnote is not needed. R2.3 covers this sufficiently. o Table 1, new footnote- We suggest a footnote be added to the column labeled “Initial System Condition” indicating that “Normal System means all transmission elements are in service and all portions of the BES within the study area are performing within specified operating limits”. Table 1 - Planning Events o Event P2 is categorized as ‘Single Contingency’; however the listed events would typically result in the loss of more than one element. In other words, Category P2 contingencies are those in which a single system element is removed from service due to one of the listed initiating events. We are concerned because it appears that all events listed for the single-contingency Category P2 are not covered under other multiple-contingency Categories. For example, a faulted Bus Section. o Events P2 and P5 are described in terms of the elements initiating a fault, while the others are in terms of number of elements out-of-service due to a contingency. Event P4 is described in terms of

Voter	Entity	Segment	Vote	Comment
				both - the elements lost and the initiating fault. It would be helpful to have additional notes explaining the apparent inconsistent wording of Planning Events. o The distinction between 'Single Contingency' and 'Multiple Contingency' Category classifications for an event must be clear. Categories A through D have worked well for the industry to this point, and it would be helpful if the transitio

Response: The SDT feels that the current definition fits the intent of the standard. Modifying the definition could have unintended consequences on other standards. No change made.

Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT agrees and has made the change.

> **Requirement R2, part 2.1 -** The Near-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, as follows:

The SDT has deleted the suggested phrase.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:

The SDT has clarified the requirement based on your comments and those of others although the term 'individually' was not added as the SDT did not see that it added any clarity.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT has clarified the requirement.

> **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the

Voter	Entity	Segment	Vote	Comment

expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT has deleted the suggested phrase.

Requirement R2, part 2.4.3 - For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:

The SDT does not see that the suggested change adds clarity. No change made.

Parts 2.1.4 or 2.4.3 were not removed so no change is needed here.

The listed items are simply that – a list of actions that would be included. This is an allowable and encouraged format for Reliability Standards. No change made.

Requirement R3, part 3.5 is part of Requirement R3 which links back to Requirement R2 where the documentation is required. No change made.

The SDT believes that the present wording is correct. No change made.

Requirement R4, part 4.1.2, deals with a single generator pulling out of synchronism. The situation you described is a system Stability issue and is considered an application for an SPS which is allowed by the standard. No change made.

Nothing in this standard precludes a region from adopting an additional requirement in the future. No change made.

The SDT modified the language of the requirement to address your concern.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

The SDT believes that your comment is for requirement R4, part 4.3.3. The SDT has modified the wording of this requirement to address your concern.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.

Voter	Entity	Segment	Vote	Comment
				• Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. The SDT does not see any reason to delete the phrase as it is not causing any confusion. No change made. The SDT believes that the present wording is appropriate. No change made. You need to model the way that Protective System is expected to operate; if there is no local backup, then remote clearing will have to be simulated. No change made. All aspects of Stability are to be considered. No change made. The present language is common in many standards and the SDT sees no reason to change it here. There may be a difference between 'current' and 'in force' due to effective dates. No change made. The SDT has made a clarifying change to the note. **Header note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. The SDT agrees and has modified the note accordingly. **e**. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. End-user equipment is that equipment owned and operated by an end-user over which an entity has no control. No change made. This is simply a matter of preference as the suggested change would not alter the meaning or intent. No change made. The SDT agrees and has deleted header note 'j'. Dynamic stability is covered in the requirements and no reference is needed in the header notes. This footnote is referring to Stability studies and not short circuit analysis. No change made. System normal, or P0, is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. The SDT has adjusted Requirement R1 to provide this clarity. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. The P2 category describes single events that may result in multiple

Voter	Entity	Segment	Vote	Comment
elements being removed from service. The P2 events differ from the multiple event categories which consider two or more sequential events. No change made. The SDT agrees that the structure of the descriptions are different because they are describing dissimilar types of events but the SDT does not feel that they are inconsistent or causing any confusion. No change made. The change was made since the table is now event based and because the four existing standards were consolidated into one standard. The industry has supported these changes. No change made.				
Fred Frederick	Southern Indiana Gas and Electric Co.	3	Negative	Definitions, Year One - Vectren disagrees with the proposed definition of Year One. Vectren believes that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from the end of the calendar year. Section 5 - Effective Date, the allowance of 60 calendar months for Corrective Action Plan implementation is too short. Recommend this be extended to 84 months to allow for proper planning, budgeting, right-of-way acquisition and construction. R2.4.1 - System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Vectren has concern with this requirement. The concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R2.7.2 - The term "include actions to resolve performance deficiencies identified in multiple sensitivity studies" causes concern. Mitigation plans should not necessarily be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are typically extreme and less likely than base case conditions. Some of the sensitivity study conditions may not be credible or plausible enough to warrant the implementation of mitigation plans. Also, what is the interpretation of multiple studies? Is that more than one, a majority, 2/3 of the number that were studied, or some other number? R2.7.3 - The term “beyond the control of the Transmission Planner or Planning Coordinator” needs to be better defined. An auditor could interpret a situation to be within the “control” of a TP or PC but are not covered by NERC standards or a TP / PC’s process, procedures or criteria. This leaves entities open to possible non-compliance violations based on an auditor’s perception of what they believe should be in the TP / PC’s control. Also, Vectren is not in agreement that Non-Consequential Load Loss should not be allowed for any case. There may be cases, especially future year studies that indicate a need for building transmission infrastructure, to serve speculative load growth. In these cases the consumers, local

Voter	Entity	Segment	Vote	Comment
				jurisdictions, and state jurisdictions may find it a prudent plan to assume some Non-Consequential Load Loss in order to defer building transmission infrastructure. R3.3.3 - Trip Transmission elements when relay loadability limits are exceeded. Vectren has concerns that system models (or software applications) cannot support the requirements of R3.3.3. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R4.1.3 - For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. Vectren has concerns with this requirement. What if the PC and the TP cannot reach an agreement in the definition of “acceptable damping”? R4.1.2 - When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Vectren has concerns that dynamics models (or software applications) cannot support the requirements of R4.1.2. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. R4.3.3 - Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. Vectren has concerns that dynamics models (or software applications) cannot support the requirements of R4.3.3. Another concern is that Vectren will be held to strict interpretation of this standard with regard to an actual event occurring that was not exactly reproduced by the Vectren model. Table 1 - Steady State & Stability Performance, Planning Events, k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner. What if the PC and the TP cannot reach an agreement in the definition of “acceptable limits”? Table 1 - Steady State & Stability Performance, Extreme Events, V. A successful cyber attack. This requirement is too vague. It could be interpreted in any number of ways.

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others’) suggestion. Since problems may not be seen

Voter	Entity	Segment	Vote	Comment
until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. 2.4.1 – The SDT has added the word 'expected' to the text to alleviate your concern. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. The results of on-going benchmarking and model development activities can be incorporated when those activities yield more representative results. **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made. If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. No change made. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The expectation of this requirement is that relay tripping would be handled consistent with their PRC-023 expectations. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. No change made. Requirement R4, part 4.1.3 does not state that the criteria are set jointly. If such an item became an issue, the SDT believes that it is covered in Requirement R7. No change made. The SDT believes that the necessary tools are readily available. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. No change made. The table does not state that the limits are set jointly. If such an item became an issue, the SDT believes that it is covered in Requirement R7. No change made. The event is the loss of two generating stations. A successful cyber attack is simply an example of a cause of the event. No change made.				
Liam Noailles	Xcel Energy, Inc.	5	Negative	Xcel Energy appreciates the hard work of the Standard Drafting Team and commends the group for making substantial improvements in every successive draft of the TPL-001-1 standard to bring it to the proposed version for balloting. However, in as much as the proposed TPL-001-1 standard has

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Michael Ibold</td><td>Xcel Energy, Inc.</td><td>3</td><td>Negative</td><td rowspan="2">improved, we cannot support its approval at this time for the following reasons:

1. Implementation Plan: Xcel Energy does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new “raise-the bar” performance requirements. Building a transmission line in Xcel Energy’s service area spanning eight-states (and two RTO’s) varies significantly in regional and local planning and review process, regulatory approval process, permitting and routing process, legal challenges, etc. These processes can often take more than 5 years to complete from the time the project is conceived as a proposed solution. Though requirement R2.7.3 is included in the standard to address situations beyond the control of the Transmission Planner, we are concerned that it leaves to the interpretation and judgment of the auditor whether the Transmission Planner is taking appropriate actions to resolve the situation and consequently whether the interim solution of dropping Non-Consequential Load or curtailment of Firm Transmission Service is acceptable. Xcel Energy will be comfortable supporting the standard if the 60 months time-frame is increased to 84 months.

2. Intended Scope of Planning Event P5: Xcel Energy is unsure of what comprises the scope of “Failure of a single Protection System” - does it imply studying the failure to operate of the relay or communication channel utilized in the primary protection scheme for an equipment (e.g. transmission line), or does it also include studying the failure of other single Protection System components such as current/voltage transformer or station battery? Note that the former interpretation will result in delayed clearing of the faulted transmission element only, consistent with operation of the local backup protection (typically zone 2 operation of line distance relays). On the other hand, the failure of current/voltage transformer or station battery could compromise the operation of both primary and local backup protection schemes for the faulted equipment, thus requiring the remote backup protection to clear the fault, which results in longer-duration delayed clearing and the loss of more than one transmission element. In Table 1, characterizing P5 as a multiple contingency event (like P4 or P7) also contributes to the scope confusion. As discussed above, a primary protection relay failure will typically result in the loss of a single (faulted) element only, not the outage of multiple elements (that always occurs in P4 or P7 events). Then, should the P5 event be construed to study the failure of CT/PT and/or station battery which, as discussed above, will typically result in the loss of multiple elements? If yes, isn’t the standard implicitly requiring redundant CTs/PTs or station batteries to enable meeting the EHV performance requirement? If no, shouldn’t the P5 event description reflect the intended scope more clearly? This may presumably be achieved by modifying P5 to read “Failure of primary protective relay that results in Delayed Fault Clearing on one of the following:”

3. Steady-state Performance of Planning Event P5 versus P1: Assuming that the intent of the P5 event is to study the operation failure of primary protection scheme (failure of the relay or its communication channel), the delayed clearing time associated with local backup protection scheme is</td></tr>
<tr><td>David F. Lemmons</td><td>Xcel Energy, Inc.</td><td>6</td><td>Negative</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				only relevant to the stability performance. If the post-contingency outcome for P5 consists of the loss of the faulted transmission element only, can the post-contingency steady state system condition for event P5 be any different than for event P1? We contend that both events will result in the same post-contingency steady-state system condition since the only difference is the normal versus delayed clearing time. If so, should the steady-state performance requirements for event P5 be any different than for event P1? For steady-state analysis, the HV level performance requirements for P5 in Table 1 become contradictory to those for P1. This is another example of why the intended scope of P5 event needs to be specified more clearly. 4. Ambiguities and Inconsistencies: Xcel Energy is providing the following editorial comments for your consideration to improve the consistency and clarity of the standard. Several, but not all, of the ambiguities and/or inconsistencies are confusing enough to qualify as show-stoppers since they prevent the standard's intent and scope to come across clearly. 4.1 Table 1 - Headnotes to Planning Events o Headnote b - At a minimum, delete "or extreme" since it is out of place in this headnote. Consider truncating at "... generation loss is acceptable." since the headnote is by default applicable to all planning events, and P0 exclusion is implicit in the context. o Headnote e - Consider omitting the phrase "For all planning events," since the headnote is by default applicable to all planning events. o Headnote i - Consider re-wording to remove the unintended association of equipment with event being implied at "...by end-user equipment associated with an event...". Suggest deleting the redundant phrase "associated with an event" since the headnote is by default applicable to all planning events. Alternatively, modify to read as follows: "Load loss resulting from an event due to the response of voltage sensitive Load or due to Load that is disconnected from the System by end-user equipment shall not be used to meet steady state performance requirements." o Headnote h - Unlike other headnotes, this does not describe a system performance but offers a clarification on applicability. Therefore, like other clarifications/qualifications, it belongs in the footnotes - suggest changing it to footnote assigned to P0. o Headnote j - It is not clear why this falls under Stability Only, and it also lacks specificity in expected stability performance. Note that the generic 'stable' is an umbrella term that includes all types of system (in)stability including voltage (in)stability, frequency (in)stability and cascading facility outages, not simply angular (in)stability. Considering that headnote 'a' includes most varieties of system (in)stability, we suggest adding "angular instability" in headnote "a" and deleting this

Voter	Entity	Segment	Vote	Comment
				headnote. 4.2 Table 1 - Footnotes Footnote 2 - Suggest deletion of “Unless specified otherwise, simulate normal clearing of faults” since it is redundant with Headnote ‘d’ for Planning Events and Headnote ‘b’ for Extreme Events. Alternatively, delete both Headnotes and do not change Footnote 2. 4.3 Table 1 - Planning Events - Column 2 - Initial System Condition - Normal System What are the attributes of Normal System? Is this term intended to be synonymous with “system intact” or N-0 system topology? Is the event P0 intended to be identical to the existing Category A? The intent is not clear and needs to be explicitly stated. We suggest that the first occurrence of the term be modified as follows: “Normal System (all Facilities in service)” to explicitly convey the intent. Note that the qualifier in parenthesis is the verbiage for Category A used in the existing TPL standards. However, we also note that if P0 is intended to be synonymous with “system intact”, then it does not appear that the base case system model built as per Requirement R1, part 1.1, will always be compatible with P0 - due to the known outages to be included in the model (part 1.1.2). Does the standard envisage P0 and “system intact” to connote “All Facilities in service minus the known outages”? If so, this must be clearly stated. .4 Table 1 - Planning Events - Column 1 - Category What is the significance of ‘Single Contingency’ or ‘Multiple Contingency’ qualifier for an event? Is it intended to characterize the number of elements outaged due to the initiating event, or is it intended to convey the number of equipment failures/faults comprising the initiating event? The NERC glossary definition of Contingency “The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.” does not help remove this ambiguity. Regardless of the chosen interpretation, inconsistency arises for the following events: Event P2 - Wouldn’t initiating events P2-2, P2-3 and P2-4 typically result in the loss of more than one element? So qualifying P2 as single contingency appears to correspond with the equipment fault/failure description in the Event column but does not correspond to the total number of elements outaged due to the initiating event. Event P3 - Per the description in the Event column, the events P3-1 to P3-5 result in the loss of one element. So qualifying P3 as a multiple contingency appears to correspond with the total number of elements outaged, after including the (overlapping) prior outage. But the multiple contingency qualification is not consistent with the initiating event description in the Event column. Event P6 - Same comment as P3. Event P1 - Can the loss of only one element be presumed as an outcome of normal clearing of a fault, which appears to be the implicit initiating event here? How about the case of a normally cleared fault on a transformer-terminated line that is not breakered at the transformer end? Or the case of a normally cleared fault on a line-connected shunt reactor that is not breakered to the line? The resulting loss of two elements is not consistent

Voter	Entity	Segment	Vote	Comment
				with the event description. And by characterizing the event in terms of loss of one element, it is also inconsistent with headnote c that requires removal of all elements expected to automatically disconnect for each event. 4.5 Table 1 - Planning Events - Column 3 - Event Descriptions for events P1, P3, P6 and P7 are in terms of number of elements (one or multiple) outaged due to the contingency, whereas events P2 and P5 are described in terms of the initiating fault only. The exception is event P4 which is described in terms of both - the elements lost and the initiating fault. Is there a good reason why the event descriptions are not consistently worded? We note that the contingency descriptions in column 2 of the existing Table I are expressed in terms of "Initiating Event(s) and Contingency Element(s)." We think this issue is closely correlated to the previous comment on the apparent lack of consistency between the contingency terminology in column 1 and the event description in column 3.

Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

3. A P5 event is different and will not duplicate a P1 event for steady state if the entity does not have fully redundant Protection Systems. No change made.

The SDT agrees and has made a clarifying change.

> **Header note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

The SDT agrees and has modified the note accordingly.

> **Header note 'e'**. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

While technically correct, the suggested change does not create additional clarity and the existing wording doe not cause any confusion in the eyes of the SDT. No change made.

Voter	Entity	Segment	Vote	Comment
This is simply a matter of preference as the suggested change would not alter the meaning or intent. No change made. The SDT agrees and has deleted header note 'j'. This is simply a matter of preference. While somewhat duplicative, it may add clarity and hasn't seemed to cause any confusion. No change made. System normal is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. The SDT has adjusted Requirement R1 to provide this clarity. **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. No change made. The SDT agrees that the structure of the descriptions are different because they are describing dissimilar types of events but the SDT does not feel that they are inconsistent or causing any confusion. No change made.				
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	Duke appreciates the hard work that has been done by the Standard Drafting Team to get the standard to this point. Duke is supportive of the standard as it helps to remove some of the 'grey' in the existing TPL standards, as well as driving actions that will improve the reliability of the Bulk Electric System. However, Duke believes that two areas in the standard need to be improved in order for Duke to vote to approve the standard. 1. Duke does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. In an email to the registered ballot body, Ameren stated " Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." Duke agrees with the point that Ameren is making that building of a new EHV transmission line can be a very lengthy process. Duke thinks that a more appropriate time frame would be 84 months. 2. Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability. Often, corrective actions to mitigate these events are local in nature and only require minor additional loss of local load to avoid major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. The transparency requirements of the new standard facilitate this type of decision making. In addition, the prohibition on non-consequential load loss for these events creates an incentive for Transmission Planners to remove lines serving load from network (serve the loads radially) so that they are characterized as consequential load. The unintended consequence of the standard would be a reduction in reliability for service to local load.</td></tr>
<tr><td colspan="5">Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others’) suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.</td></tr>
<tr><td>Charles A. Freibert</td><td>Louisville Gas and Electric Co.</td><td>3</td><td>Negative</td><td rowspan="3">E.ON U.S. suggests that Extreme Event 2e be clarified by adding: if generating was added in front of station, “Loss of all generating units at a generating station.” This would distinguish from a loss of all units at a transmission station. Also, it is consistent with 3a, “Loss of two generating stations ...”.

E.ON U.S. objects to the modification of P2-1 to only include “Opening of a line section w/o a fault”. Footnote 7 indicates that this is to ensure that radial load that would have tripped with a fault can be served. This is a new criteria that opens a line without an actual fault and may result in converting some of these lines to radials to comply with this requirement which could decrease overall reliability.</td></tr>
<tr><td>Charlie Martin</td><td>Louisville Gas and Electric Co.</td><td>5</td><td>Negative</td></tr>
<tr><td>Daryn Barker</td><td>Louisville Gas and Electric Co.</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: The SDT assumes that you meant 2d and of so, agrees and has made the change.

Extreme event 2d. Loss of all generating units at a generating station.

This is not a new criterion as this is exactly what was in TPL-002-0, Table 1, Category B “Loss of an Element without a Fault.” No change made.</td></tr>
<tr><td>Luther E. Fair</td><td>Gainesville Regional Utilities</td><td>1</td><td>Negative</td><td>Even though I am voting negative on this version of the standard, I want to acknowledge the considerable effort that the SDT has put into developing this change to the NERC Standard TPL-001, Transmission System Planning Performance Requirements. I do consider it, in most part, an improvement to the existing standard, but I feel it falls short by not providing more clarity and less ambiguity. As a very small utility that happens to have chosen a 138 kV loop to circle its city to serve</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				its citizens, we feel unreasonably burdened at times to accomplish the documentation task at hand. I offer the following as a few examples of concern: GRU believes that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Yes, it may be possible to arrange an agreement with a neighboring entity for use of their spare, but that assumes that the neighboring entity's transformer specifications are similar enough for use as a spare, which may not be the case. Order 693 states at Paragraph 1725: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". Next, Requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement ought to have the flexibility afforded in 3.3.2 where the planner can use a conservative assumption and screening methods (e.g., the proposed curves of PRC-024) for relay loadability (e.g., the requirements of PRC-023). Requirement 4.3.1 would also require modeling of nearly every phase distance relay in the Interconnection, again because it applies to extreme events and we will not know ahead of time where the power swings will traverse distance relay characteristics. I look forward to the next generation of this standard's development. L. Earl Fair

Response: The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. The SDT disagrees that the modeling of phase distance relays is required. No change made.

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

Voter	Entity	Segment	Vote	Comment
• Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	Exelon is concerned with the use of the term 'Protection System' in Category P5 of the Table 1 performance criteria. 'Protection System' is a defined term in the NERC Glossary (Protection System - Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry). Thus, a potential interpretation of the standard as currently proposed would be that the loss of a station battery is to be included in analysis as a valid single contingency. We understand that the SDT response to previous comments on this issue indicates that the battery contingency was not intended to be part of the P5 contingencies. However, no changes or clarifications were subsequently made to the proposed Standard to clarify the requirements and exclude this interpretation. This leaves open the potential for multiple interpretations of the Standard and creates ambiguity for the functional entities that will have to implement the revised Standard. Additionally, Exelon is concerned that performance criteria in the draft Standard is based on the voltage level of the contingency element rather than the monitored element.
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). The SDT placed greater emphasis on the facility being removed than the monitored remaining intact Facilities. The outage of an EHV Facility will typically be of greater concern for the potential of transferring power flow to lower voltage parallel paths than the reverse. No change made.				
Pat G. Harrington	BC Hydro and Power Authority	3	Negative	File: NERC_Std_TPL-001_Draft05_Ballot_Comments_BCH20100226.doc A. GENERAL COMMENTS The standard needs to better define the pre- and post-contingency generation dispatch conditions and stipulate that the worst-case combination of possible load levels and generation dispatch must be studied. For example, the portion of a transmission network connecting a “generation-rich” region (ie, a region with much more generating capacity than local load) to the rest of the BES, should be able to operate within normal voltage level limits without overloading any elements under normal system conditions (N-0). If there are intermittent resources like wind parks or run-of-the-river hydro plants that the system is not depending on to supply dependable generating capacity (or at least not to the full nameplate rating of those resources), generation shedding or run-back can be permitted for single-contingencies (N 1 situation). The amount of generation shedding should be limited to the difference between the aggregate maximum generating capacity of the region and the aggregate

Voter	Entity	Segment	Vote	Comment
				dependable generating capacity of the region and there should be further limits defined for generation shedding/run-back as described below. Add the following definitions: o 1. Consequential Generation Loss: All Generation that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault. o 2. Non-Consequential Generation Loss: Dependable Generating Capacity Loss that does not include: (1) Consequential Generation Loss, (2) Generation loss due to low voltage or (3) Generation loss due to protective relays of the generating unit or its step-up transformer. o 3. Dependable Generating Capacity: The level of generating capacity of a plant or unit that the system operator can count on to serve Non-Interruptible Load by virtue of the plant or unit's fuel supply being available to provide that level of generating capacity more than 97% of the time. "EHV" and "HV" need to be defined because they are not defined in the NERC Glossary (NERC Glossary (use "Edit, Find on this page..." and look for "Glossary": http://www.nerc.com/elibrary.php?doc_class=&doc_dept=&submit=Filter) B. SPECIFIC COMMENTS R2, 2.2.1: The system configuration of the last year of the planning period should be studied as well as at least one other year that is most-likely to fail to meet planning criteria with an explanation for why that year is considered the worst case. As it is written, it would be quite acceptable for the TP and/or TC to simply study the year immediately following a major system upgrade with the rationale being that it would likely be the least likely system condition to fail any reliability standards. As it is written, there is no requirement that the rationale provided be logical or reasonable. R2, 2.4: "Stability analysis" does not cover all of the dynamic criteria that need to be met. A more general term, like "Stability and dynamic simulation studies" should be used. "Stability" is defined by NERC as just, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", but the assessments done in what people term "Stability" studies involve more than a check on the electromechanical stability (equilibrium) of the system. Voltage sags and swells, frequency deviations and short term overloading of equipment (eg, transient and dynamic current fluctuations through series capacitors that would provide an indication of the voltage stress across the capacitor dielectric) are usually included in "Stability" studies. R2, 2.4.1: "...for one of the five years" should be changed to "...for the most critical year of the 5 year Near-Term planning period". R2, 2.4.2: This requirement needs to be better defined. Is this requirement meant to demonstrate acceptable system performance during maintenance outages over the daily peak load periods of the off-peak season (ie, summertime for a winter-peaking region) or is this intended to address light-load

Voter	Entity	Segment	Vote	Comment
				issues like over-voltages and frequency deviations? R3, 3.2 The performance requirements for extreme events need to be defined in more detail. The criteria for acceptable system performance for extreme events seems to be only described vaguely in R3 item 3.5. R3, 3.5: Change "Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created" to, "Those extreme events in Table 1 that are expected to produce more severe System impacts most likely to cause Cascading,, equipment damage or pose a significant risk to public or worker safety [needs to be further defined] shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created" Also, simply providing "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s)" is inadequate. One or more SPSs should be defined and studies should demonstrate that they prevent cascading outages and isolate, in a pre-planned controlled manner, the portion of the system experiencing the extreme event to minimize the extent of the disturbance. If necessary, an SPS should be provided that isolates the control area experiencing the extreme event from the rest of the interconnected system. R4, 4.1.1: Add (referring to the additional text suggested below for Note e of Table 1), "The amount of generating capacity disconnected or "run-back" by a Special Protection Scheme (SPS) shall be limited in accordance with Note e of Table 1". R4, 4.1.2: Add, "Studies shall be conducted to demonstrate that all circuit breakers that may be called upon to trip for an out-of-step condition (180 degrees across the open breaker) are properly rated for this duty considering the worst case voltage on any isolated transmission circuits due to trapped charge." R4, 4.1.3: Acceptable damping should be defined (eg, "studies must show that any oscillations are damped to less than 10% of their initial magnitude within 30 seconds") [or develop a different specific requirement that can be measured]. R4. 4.5" Change "Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created" to, "Those extreme events in Table 1 that are expected to produce more severe System impacts most likely to cause Cascading, equipment damage or pose a significant risk to public or worker safety [needs to be further defined] shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created".

Voter	Entity	Segment	Vote	Comment
				Also, simply providing “an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s)” is inadequate. One or more SPSs should be defined and studies should demonstrate that they prevent cascading outages and isolate, in a pre-planned controlled manner, the portion of the system experiencing the extreme event to minimize the extent of the disturbance. If necessary, an SPS should be provided that isolates the control area experiencing the extreme event. R5 & R6: Shouldn’t the Load Serving Entities (LSEs) define system performance criteria instead of the Transmission Planner or the Planning Coordinator? The LSEs have an obligation to their customers and must demonstrate to their regulators that they are providing acceptable system performance and reliability of supply to their customers. The Transmission Planner and Planning Coordinator have less incentive to provide high levels of system performance. Due to regulatory difficulties in getting approvals for transmission system upgrades, there

Response: The standard requires a normal System model, P0, be developed that projects anticipated conditions for the period under study. Any additional stress of the System prior to loss of an element would be handled through sensitivity analysis as required in Requirement R2. In addition, the SDT explored the possibility of placing limits on the amount of generation runback and the industry clearly indicated in comments that they did not support such limits. No change made.

The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made.

One can always study additional years if so desired. The SDT believes that “rationale” implies logic and reason. No change made.

The SDT intended for the term Stability analysis to include system Stability and unit Stability analyses. These analyses could include all aspects of Stability that you mentioned. It is left up to the judgment of the Planning Coordinator/Transmission Planner to decide which aspects of Stability may produce more severe results and therefore, must be analyzed. No change made.

The critical year can only be determined after reviewing the entire portfolio of current and past studies and is not a pre-determined condition. The SDT expectation is that an entity is building a portfolio over time that covers the entire planning horizon and thus determines any critical periods. No change made.

The requirement was intended to cover all conditions that could occur during Off-Peak periods. No change made.

Requirement R3, part 3.2 contains no performance obligations. It is simply a requirement to assess the impacts. No change made.

The SDT made a clarifying change to the requirement.

> **Requirement R3, part 3.5 -** 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. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">Due to the complexity associated with extreme events, the SDT believes it is inappropriate to require any more than a list of possible actions. An SPS could be a solution but it is not the only one. No change made.

The SDT explored the possibility of placing limits on the amount of generation runback and the industry clearly indicated in comments that they did not support such limits. No change made.

This standard is not intended to address engineering specifications such as proposed here. No change made.

There is no single definition; the SDT has left it up to each Planning Coordinator or Transmission Planner to define. No change made.

The SDT has made a clarifying change to the requirement.

Requirement R4, part 4.5 - 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 R4, part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Due to the complexity associated with extreme events, the SDT believes it is inappropriate to require any more than a list of possible actions. An SPS could be a solution but it is not the only one. No change made.

These are System requirements for the BES and properly belong to the Planning Coordinator and Transmission Planner. No change made.</td></tr>
<tr><td>Paul Shipps</td><td>Lakeland Electric</td><td>6</td><td>Negative</td><td>Five years is not enough time in many circumstances to build significant new transmission lines.</td></tr>
<tr><td>Joseph G. DePoorter</td><td>Madison Gas and Electric Co.</td><td>4</td><td>Negative</td><td>Our concern is that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years.</td></tr>
<tr><td colspan="5">Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Negative	FPL Comments on TPL-001-1 Standard FPL believes the Standard requirements need to be clear and unambiguous. The SDT has addressed many of the gray areas of Draft four in their consideration of comments however these comments are not part of the Standard that is currently out for ballot. Incorporating these types of clarifing comments with the use of footnotes in the Standard to help clarify the intent would be a significant improvement for anyone interpreting the Standard including an auditor or investigator. The definition of Year One is an unnecessary departure from the planning practices used in most of the Eastern Interconnection. It is recommended the phrase end of the current calendar year be changed to the current calendar year. This change will allow PAs to begin their near term analysis with either next year or the year after as deemed appropriate. The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Absent this, the 60 calendar month phase in period described in the Introduction section is too short for transmission facilities rated above 300 kV. Approval and permitting of EHV transmission lines is extremely difficult and time consuming in most parts of the Eastern Interconnection. The phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are mush less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive. Requirement 2.5 represents a significant expansion of Stability Studies into the Long Term horizon. In many cases the stability issue in long term scenarios will be with the response of new generating plants to fault scenarios such as a breaker failure event. The protection upgrades needed to mitigate performance issues are easily

Voter	Entity	Segment	Vote	Comment
				accomplished in the short term. The uncertainty of compliance judgement of rationale documentation will force a tremendous amount of unnecessary study work. It is recommend Requirement 2.5 be removed. We concur with the SDT's opinion expressed in the most recent consideration of comments that the individual component level evaluation of protection systems and redundancy requirements should be covered under the PRC standards and that the intent of the protection failure contingencies specified in Table 1 is to simulation the failure of a single protection scheme. The event description for the P5 contingency was revised in draft 5 but it continues to reflect a range of protection component failures that greatly exceed the intent of the SDT. The term Protection System is in direct conflict with the intent of the SDT, as it is defined in the Glossary to include components such as station batteries. The term Protection System should be replaced with Protection Scheme in Table 1. Requirement 4.3.1 can be interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; Simulate the operation of Protection Systems and other automatic controls as they would be expected for each contingency. The SDT has indicated in their responses to previous comments on requirement R4.3.3 that generic relay models could be used for screening purposes. While we agree with this as a practical method, the language of R4.3.3 could be interpreted to require explicit modeling of all protection and controls which is neither practicable nor an effective use of engineering resources. It is recommended that R4.3.3 be deleted.

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as

Voter	Entity	Segment	Vote	Comment

stated in the requirement. No change made.

The SDT has clarified the requirement to address your concern.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** 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:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** 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:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Voter	Entity	Segment	Vote	Comment
Thomas W. Richards	Fort Pierce Utilities Authority	4	Negative	FPUA believes that 5 years is not enough time in many circumstances to build significant new transmission lines. Seven years is a more appropriate lead time for the implementation plan / effective date. FPUA believes that requirement 2.1.5 on spare equipment strategy is discriminatory for smaller entities. For many smaller entities, having a spare transformer is not a practical solution and makes far less sense and has significantly more customer rate impacts than for a larger utility. Order 693 states at Paragraph 1725: "… the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages in requirement 2.1.5, in other words, if an entity has no plans for a long term outage of a transformer, it should be excluded from the assessment of 2.1.5. Such a condition would allow an entity to assess things like gas in oil analysis to predict when a long term outage might be planned, and the flexibility between start and end dates of that planned outage. Requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement ought to have the flexibility afforded in 3.3.2 where the planner can use a conservative assumption (e.g., the proposed curves of PRC-024) for relay loadability (e.g., the requirements of PRC-023). Requirement 4.3.1 would also require modeling of nearly every phase distance relay in the Interconnection, again because it applies to extreme events and we will not know ahead of time where the power swings will traverse distance relay characteristics. FPUA agrees with Ameren's concerns about the ability of the programs to actually be able to model this requirement and FPUA fears that we are setting ourselves up for failure. We suppose that "generic" relays could be modeled to observe what distance relay characteristics are actually crossed by power swings and then, for that simulation, go back and individually model the actual relays for that specific simulation, but, that is a labor intensive process, not to mention the level of effort that would be required to maintain an interconnection wide database of relay settings. FPUA believes that the SDT ought to evaluate the perceived increase in accuracy that is intended with these requirements. It is FPUA's belief that the expected increase in accuracy is lost when considering other simulation inaccuracies that we really cannot improve (e.g., load modeling, load level modeled, dispatch modeled, etc., versus what would happen in an actual event) until much more work is done on improving our understanding of dynamic load behavior, benchmarking the model to actual system events, and possibly improvements on the ability to perform "real-time" stability analyses so that we have more practical operating experience to insert into our planning processes. Let's be practical in understanding the level of accuracy we can reasonably achieve in our simulations and model in accordance with that level of accuracy.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** 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: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Harold Taylor, II	Georgia Transmission Corporation	1	Negative	Georgia Transmission Corporation (GTC) supports the efforts of the study team and believes that their efforts to improve the Standard are moving in the right direction. However, we have identified the following concerns which prevent us from voting "affirmative". 1. GTC echoes ATC's concerns with the use of the word "control" in R2.7.3. (ref. ATC email; From: Shaver, Jason To: Gilbert, Don C. Manager, Electric System Planning ; bp-2006-02_ATFNSDT_TPL_in@nerc.com Sent: Wed Feb 24 09:43:11 2010 Subject: RE: Comments on TPL-001-1, Project 2006-02) An auditor could identify many things that may reasonably be within the "control" of a TP or PC, that are not covered by NERC standards or a TP / PC's process, procedures or criteria. This wide area of discretion leaves entities open to findings of possible non-compliance based solely on an auditor's perception of what he or she believes should be in the TP / PC's control. In addition, the concept of "control" must be limited to an entity's compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words, an entity must be allowed the ability to identify situations which fall under its "control" as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its

Voter	Entity	Segment	Vote	Comment
				Transmission Planner or Planning Coordinator functions. 2. R2.7.2 - "include actions to resolve performance deficiencies identified in multiple sensitivity studies" - Mitigation plans should not be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. It is not clear if the interpretation of multiple studies is more than one or a majority of the number that were studied. 3. Throughout the Standard there are circular references that make the interpretation confusing. We recommend that all references should refer back to previous sections and not to future sections, thereby avoiding circular references. 4. We disagree with the proposed definition of Year One. Year One should be the planning window that begins 12-18 months from the start of the calendar year, and not from the end of the calendar year. This would require minimal adjustments to the ERAG MMWG model building process. The proposed definition would force additional models to be built by the MMWG. 5. We agree with others that the timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years. GTC is aware of Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but believes that the proposed language is ambiguous. 6. We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. This information should be supplied by the LSE as part of the MOD standard. We understand that the proposed standard will accept an aggregate system load model which represents the overall dynamic behavior of the load to relieve the burden of trying to develop specific induction motor load representation at each load bus. However this modeled system response will be considerably different compared to the actual system response which will open up the industry to unwarranted scrutiny and possible compliance violation investigations. 7. We disagree with the inclusion of low voltage ride-through in requirement R3.3.2. Low voltage ride-through is a dynamic modeling issue as correctly included in requirement R4.3.2. 8. "EHV" and "HV" need to be defined in the NERC Glossary. 9. Requirement R2.4.2 needs to be better defined. It is not clear if this requirement is meant to demonstrate acceptable system performance during maintenance outages over the daily peak load

Voter	Entity	Segment	Vote	Comment
				periods of the off-peak season or intended to address light-load issues like over-voltages and frequency deviations. 10. A better definition for Consequential Load Loss is needed. The Non-Consequential Load Loss definition conflicts with the Consequential Load Loss definition. The Response of Voltage Sensitive Load exception under the Non-Consequential Load definition is a circular reference. It is not clear whether Voltage Sensitive Load is Consequential Load Loss or Non-Consequential Load Loss. 11. It is not clear if Consequential Load Loss is intended to be limited to: a) Load between two open (breaker/switches) protective devices and b) Protective devices (breakers/switches) for radial load. 12. Requirement R1.1.5 states that the system model shall represent "Known commitments for Firm Transmission Service and Interchange". GTC requests clarification of how to represent "Known commitments" whose collective magnitude can exceed the Load requirements.

Response: 1. If an entity can demonstrate that it has made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

2. Requirement R2, part 2.7.2 already states that an entity must supply the rationale for when actions were not necessary so the SDT believes that your concerns have already been addressed. No change made.

3. The SDT has made every attempt to make the standard as easy to follow as possible and believes that all references cited in the standard are correct. No change made.

4. Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

5. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

6. The SDT does not disagree that the Load Serving Entity may provide the initial information but someone needs to be responsible for adapting the model accordingly and that entity has to be the Transmission Planner or Planning Coordinator. No change made.

7. The SDT voltage ride through is not confined to the dynamic period. There are protection requirements that could result in generator tripping and that must be

Voter	Entity	Segment	Vote	Comment
considered in the steady-state analysis. The SDT has clarified the wording of the requirement. **Requirement R3, part 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. • Tripping of Transmission elements where relay loadability limits are exceeded. 8. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 9. The requirement was intended to cover all conditions that could occur during Off-Peak periods. No change made. 10. The definitions are not in conflict as the definition of Non-Consequential Load Loss specifically states that it doesn't include Consequential Load Loss. The response of Load to voltage is not classified as Consequential or Non-Consequential Load Loss. This standard articulates how voltage sensitive Load should be treated during different time periods of a simulation. No change made. 11. Both examples provided are Consequential Load Loss per the definition. 12. The SDT does not believe that a continent-wide standard should proscribe a single approach. Requirement R1 states that an entity must document its assumptions. No change made.				
Gordon Pietsch	Great River Energy	1	Negative	GRE recommends the following revision to the wording in subrequirement 2.5: "…the impact of proposed generation additions that have made a commitment to interconnect with the Bulk Electric System…" In addition, it appears that the drafting team has inadvertently included additional compliance requirements in the language of Table 1. The net result of this is that these requirements are effectively buried in the Table 1 language. GRE does not take exception to these additional requirements but believes that they should be included in the Requirements section of the Standard. Having the Table 1 language written as it is presents additional risks for non-compliance that would not otherwise be there if these requirements would be included in the Requirements section.
Response: The SDT has clarified this requirement based on industry comments. **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.				

Voter	Entity	Segment	Vote	Comment
Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Jacquie Smith	ReliabilityFirst Corporation	10	Negative	In R1.1.6 is OR the proper desciption of resources? Shouldn't this be AND? Resources are both supply AND demand side. Is R4.1.2 too stringent. At the least, shouldn't there be an exception for Special Protection Systems and Remedial Action Schemes to trip for apparent impedance swings? In 4.3.1 shouldn't the analysis be for both successful high speed reclosing and for unsuccessful high speed reclosing, (AND instead of OR) In Measure 8, the mixture of OR and AND is confusing. As presently written, as long as no entity makes a written request for the information they pass the test. Thus, as long as your neighbors do not complain about not receiving the information an entity is compliant. Better wording would be: The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, or one of its adjacent Planning Coordinators, or to one functional entity ...... The responsible entity failed to distribute the results of its Planning Assessment to two or more of its adjacent Transmission Planners, adjacent Planning Coordinators, functional entity ...... Also, I think failure to distribute results is more severe than failing to respond to comments. Failing to give their neighbors an opportunity to comment is less severe than failing to acknowledge comments. I presume that the documented response to comments can be nothing more than "Thank you for your comments." All of the above are minor compared to this next problem. (I believe this needs to be addressed before we can vote yes.) The level of detail of Planning Assessment results is missing from the requirements. Is a message to your neighbors stating that you have performed a Planning Assessment and everything is OK, enough to meet the requirement, or does it need to be more detailed? The minimum contents of the Planning Assessment results shared with Transmission Planners, Planning Authorities, and other functional entities needs to be clearly stated. Also, the RRO is not a functional entity. As written, can this standard be used as justification for not sending detailed Reliability Assessment information to the ReliabilityFirst? Would requiring sharing with Stakeholders with a reliability need be better than limiting the required sharing to functional entities?
Response: The SDT believes that 'or' is appropriate. This allows for an entity to model supply or demand or both as appropriate. No change made. Requirement R4, part 4.1.2, deals with a single generator pulling out of synchronism. The situation you described is a system Stability issue and is considered an				

Voter	Entity	Segment	Vote	Comment

application for an SPS which is allowed by the standard. No change made.

The SDT has clarified the language of Requirement 4, part 4.3.1, bullet #1 to address your concerns and those of others.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Measure M8 had a typo which has been corrected. The remainder of the comment seems to be directed to VSLs and the SDT reviewed the VSLs and has made a clarifying change.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that functional entity has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners, one adjacent Planning Coordinator, or to one functional entity that has a reliability related need and that has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to more than one of its adjacent Transmission Planners, adjacent Planning Coordinators, or functional entities that have a reliability related need and that have submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

The definition of Planning Assessment details what must be exchanged. No change made.

Voter	Entity	Segment	Vote	Comment
Any functional entity such as a Regional Entity or Reliability Assurer would qualify which would allow RFC to get the information. No change made.				
Kathleen Goodman	ISO New England, Inc.	2	Negative	ISO New England is submitting a negative vote on the TPL-001 standard, because: 1. Section 2 of the standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This creates unnecessary study work and must be changed in order for ISO NE to support the standard. 2. In Table 1 - Steady State & Stability Performance Planning Events, Category P5 wording for the EHV contingency continues to call for no loss of load in the event of the loss of a single protection system. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: “A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event”. It is ISO New England’s opinion that similar language to the comment response should be incorporated into this requirement. 3. ISO New England has additional reservations about the standard that should be addressed in subsequent revisions however items 1 and 2 here must be addressed for ISO New England to support the standard.

Response: 1. The intent of the SDT wasn’t that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.
>
> **Requirement R2, part 2.1 -** The Near-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, as follows:

2. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

3. Without any specific comments to address, the SDT is unable to further address your concerns at this time. No change made.

Voter	Entity	Segment	Vote	Comment
Brian Conroy	Central Maine Power Company	1	Negative	Issues with TPL-001-1 draft 5 in ballot: R 1 & 2 - There is insufficient direction/specification regarding base case development and sensitivity testing. Only “known outage(s) of generation” is specified. R2.1.1 - Year One or year two are operating time frame studies. Year five, particularly with additional load from load growth, is appropriate for system planning. There should not be a requirement for any more than one short-term and one long-term steady-state assessment. 2.1.5 - The ‘spare equipment strategy’ requirement effectively amounts to a N-1-1 analysis, but without the system adjustment between contingencies. A N-1-1 analysis should be sufficient. R2 - An annual assessment of the system is required regardless of whether system conditions are essentially unchanged from year to year. Note that R2.6 is only for ‘support’ and are ‘supplementation.’ This creates unnecessary study work and must be changed in order for ISO NE to support the standard. R2.4.1 - The dynamic load model must consider the behavior of induction motor Loads in the stability assessment. The behavior of customers’ induction motor loads is not known. Table 1, Category P5, EHV - loss of load in the event of a fault plus the loss of a protection system, should be allowed. This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: “A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event”. The draft standard is too prescriptive in some areas and too open to various interpretations in others.

Response: System normal, or P0, is the starting system condition for the projected study conditions per the model developed in accordance with Requirement R1. Requirement R1 contains more than just ‘known outages of generation’ that need to be considered. The SDT has adjusted Requirement R1 to provide this clarity. The SDT believes that sufficient direction on sensitivities is in the requirement but the SDT has made a slight clarifying change to the requirement.

> **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1.

The SDT has changed the definition of Year One to more clearly show the SDT’s intent. The SDT believes that two near-term studies are necessary in order to calibrate the planning assumptions against operations (Year One or year two) and to provide an additional data point for interpolation (Year One or year two and

Voter	Entity	Segment	Vote	Comment

year five).

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

An annual Planning Assessment is required but it can be supported by current or past studies. The SDT has clarified Requirement R2, part 2.1 accordingly.

Requirement R2, part 2.1 - The Near-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, as follows:

The SDT has changed Requirement R2, part 2.1 as indicated above to address your concern.

2.4.1 The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made.

The SDT disagrees that Non-Consequential Load Loss should be allowed for EHV. The SDT feels that it was appropriate to raise the bar on situations that would impact the reliability and performance of the System and considered above 300 kV as the backbone of the System and thus needs to be extremely reliable and was an appropriate place for raising of the bar.

The SDT has changed the text for the P5 event as a result of comments.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Voter	Entity	Segment	Vote	Comment
Lorees Tadros	Omaha Public Power District	1	Negative	It's unclear what the intent of the SDT was in Requirement R6, especially when R6 is considered in conjunction with Measurement M6. R6 includes the phrase "for conditions such as Cascading, voltage instability, or uncontrolled islanding", while M6 does not. R6 and M6 should use parallel language, similar to the way R5 and M5 use parallel language. Additionally, why is "System instability" mentioned in R6 for conditions such as Cascading, voltage instability, or uncontrolled islanding, when in Note "a" at the top of Table 1, the requirement that Cascading, voltage instability, and uncontrolled islanding not occur applies to both steady-state and stability analysis? In Note "f" at the top of Table 1, the word "applicable" was inserted in front of the term "Facility Ratings". The word "applicable" is unnecessary and should be struck. Inclusion of it could lead to certain Planning Coordinators and Transmission Planners interpreting it in ways that were never intended by the SDT. The word "applicable" should also be struck from Footnote 9 of Table 1. A reference to Footnote 9 was added to each occurrence of the word "No" in the second-to-last column of Table 1. This is confusing, because a "No" in this column means that interruption of firm transmission service is not allowed, while Footnote 9 says that curtailment of firm transmission service is allowed. This needs to be clarified.

Response: The SDT agrees and has revised the wording accordingly.

> **M6.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

Requirement R6 is documentation for criteria and methodology for risk exposure to those items. The SDT does not believe it is in conflict with header note 'a'. This is parallel to using thermal ratings to determine if lines become overloaded during the analysis. No change made.

The word 'applicable' is correct as ratings vary over time and the standard must accommodate this situation. No change made.

As a general rule, curtailment is not allowed. The footnote sets out exceptions to that as long as the conditions in the footnote are met. The SDT believes that this is the proper method to present the concept. No change made.

Voter	Entity	Segment	Vote	Comment
Garry Baker	JEA	3	Negative	JEA is concerned that there are some limited prudent cases where consumers, local jurisdictions, and state jurisdictions may find it prudent to plan on some Non-Consequential Load Loss in order to defer building transmission infrastructure for the overall benefit of the consumer. Therefore, JEA proposes the addition to the standard that allows the use of Non-Consequential Load Loss for local area planning.
Brad Chase	Orlando Utilities Commission	1	Negative	OUC appreciates that hard work of the STD and of the industry in reviewing and commenting on these standards. The STD has worked hard to try to address the concerns of the industry. OUC is voting against these standards. The proposed standard raise the bar in terms of study and performance requirements, an increase that will result in a non trivial increase in costs for utilities to meet the standards. The change in the standard did address some ambiguities in the old standard, but also introduced some new ones. Reviewing the new standard against the old OUC finds that our cost and that of our neighbors will increase to meet these standards. However OUC does not believe there will be a real increase in reliability on either the bulk system or at the individual user level due to these increased costs. In the current environment the direction from our customers is to keep rates as low as possible, and from our regulatory agency it is to have as little environmental impact as possible. The customers and regulatory agency do look at outages, but transmission is very rarely a contributor to those outages and funds expended can be better spent elsewhere, like on the distribution system or hurricane hardening, then on studying and constructing redundant transmission facilities that provide little to no increase in the end user's reliability. The standard also reduces the range of circumstances where non-consequential load loss is acceptable. OUC does not generally rely on consequential load loss for these circumstances, but this is a choice made based on feedback from our customers and local regulatory authorities. Consequential load loss, when confined to a limited area, is not a Bulk Electric System reliability issue. It is an issue best addressed locally where the cost in terms of capital facilities, condemnation, environmental impacts, probability of event and severity of event can be evaluated and a decision made that addresses these issues. A miniscule decrease in the risk of an outage would often be desirable to the community due to the subsequent rate increase and the impact of constructing power lines through their wetlands, scenic and urban areas. Since such an outage is not even noticeable at a regional scale, the choice should be left to those impacted, not mandated by NERC.
Richard Kinas	Orlando Utilities Commission	5	Negative	
Ballard Keith Mutters	Orlando Utilities Commission	3	Negative	
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance

Voter	Entity	Segment	Vote	Comment
				reliability issues with cost of service issues. Requiring remediation by a date certain could frustrate the coordinated siting of new lines with other planned infrastructure upgrades such as highways or bridges. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Mike Laney	Luminant Generation Company LLC	5	Negative	Luminant supports the concept of a more robust transmission planning criteria as described in TPL-001-1, but has serious concerns about the timeline being proposed. The 60-month implementation timeframe associated with the elimination of non-consequential load loss does not have any mechanisms to respect the base level of construction activity already underway in the various NERC regions that may materially impact compliance with a 60-month timeline. In ERCOT, the Public Utility Commission of Texas (PUCT) has mandated the construction of over 4,400 circuit miles of transmission within the next five years to support over 18,000 MW of wind generation. The PUCT Competitive Renewable Energy Zones (CREZs) build out plan requires the ERCOT 345 kV transmission network to be expanded by ~51% (in terms of total circuit miles), necessitating complex coordination of transmission clearances for construction of new lines, making it difficult to economically operate in a secure manner. These new CREZ transmission facilities are scheduled for completion by 2014 (i.e., within the next 5 years). The concurrent implementation of TPL-001-01 will compete with the CREZ build-outs and other on-going transmission upgrades needed to support load growth in the ERCOT region, which has historically experienced higher load growth rates than other parts of the country. Given that these major activities (including CREZ) reflect the most aggressive transmission build out plan in the history of ERCOT and that the implementation of TPL-001-1 will only add to that, Luminant is concerned that adding the implementation of TPL-001-1 on top of these activities will not provide adequate clearance windows to economically or reliably implement this plan within the proposed 60-month implementation window. In light of these concerns, Luminant proposes a 120 month implementation timeline of TPL001-1 for the ERCOT region Additionally, Luminant would like to see safeguards added to TPL-001-1 that acknowledge that each NERC region must complete all of the identified transmission upgrades associated with implementation of TPL-001-1 before NERC regions are required to begin operating with this level of security constraints enforced. Given that it is not possible to operate a NERC region any more securely than it is planned to be operated, this type of safeguard may readily apparent, but explicitly

Voter	Entity	Segment	Vote	Comment
				stating it would still be helpful. With the modifications outlined above, Luminant could support TPL-001-1. Thanks for the opportunity to comment.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has extended the implementation plan as described above and that Requirement R2, part 2.7.3 provides sufficient latitude for entities to accommodate your concern. No change made.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	MidAmerican find P5 confusing. What analysis is required? Does P5 specify the analysis of individual components of a System Protection system, the entire protection system as a whole, or something else? Do the benefits justify the requirement?
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
John Canavan	NorthWestern Energy	1	Negative	NorthWestern Energy Rationale for our Vote NO: Below are NorthWestern's Comments on TPL-001-1 Draft 5: January 6, 2010: While this document has improved slightly with each successive draft, there are still several flaws that persist that NorthWestern finds to be unacceptable: 1. The definition of a Bus-tie Breaker is vague. As a practical matter any breaker could qualify. 2. The definition of Non-Consequential Load Loss doesn't fit its name. 3. The idea of a Planning Assessment (developed throughout the document) is loose enough that it seems always to be asking the Transmission Planner to "do another comprehensive study anyway just to be sure you won't get sanctioned". There were numerous discussions about this, but the Drafting team has not cleaned up the language on this. The original idea was that a TP whose comprehensive study was not rendered unusable by the developments of a single year could perform an Assessment, and reasonably re-use the results of that study for the following year. The language in R2.1 contains the language: "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:" This language

Voter	Entity	Segment	Vote	Comment
				convinces any Transmission Planning person that an annual analytical study complete with power flow simulations is required. This requirement is onerous, since there is a significant waste of manpower and resources involved in conducting such a study when for most years a bi-annual study program would clearly be sufficient. NorthWestern considers that this one issue is worthy of a NO vote based on the excessive nature of the requirement. 4. The language in R2.3 requires a short circuit analysis to be conducted annually. As with our comment 3 above, we find this excessive. This level of vigilance is not commensurate with the potential threat of a situation where fault duty could exceed breaker interrupting capability. 5. The stricter requirements in the table for EHV lines certainly “raise the bar” for these facilities. They are also likely to reduce the enthusiasm for building such facilities. The outcome of this may be unintended consequences that are far more onerous to society that the amount of load loss that is avoided by the standard. It is not clear that this addition to the standard is well reasoned. 6. NorthWestern is concerned about the potential for uneven treatment by various auditors as they follow this standard. While there is some risk of this for any standard, we believe the language in this standard is still weak. 7. The 60 month time limit for implementing Corrective Action Plans may be quite unrealistic in the Montana transmission line environment. It really is not clear what is in the Transmission Planner’s “control” in this arena. 8. The definition of “year one” is problematic. Presently the WECC does not produce base cases that are well suited to this choice. We would like to encourage the Drafting Team to work to “tighten up” the language in the standard. This particular standard is so important to the general reliability of the transmission system (BES) that it deserves an extra effort at clarity, conciseness, and thoughtful language to achieve truly beneficial practices in the design of the BES. We believe that a “NO” vote is our best recourse to promote this extra effort. We understand that this standard has been a “long time in the making”. That is because it is truly a difficult drafting challenge, not because of a poor effort.

Response: 1. The definition has been iterated several times based on industry comments in the past and seems to have been accepted by the overwhelming majority of the industry to date. No change made.

2. The use of non-consequential is in line with the previously used term ‘consequential’ and doesn’t imply that it isn’t important. No change made.

3. The intent of the SDT wasn’t that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

Voter	Entity	Segment	Vote	Comment
Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-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, as follows: 4. Past studies are allowed as long as they qualify as per Requirement R2, part 2.6 and that should alleviate your concern. No change made. 5. There are many other factors over and above this standard that will determine what entities build in the future. The SDT and many stakeholders believe that it is important to raise the bar for reliability. No change made. 6. The SDT has made every attempt to make this standard clear, unambiguous, and enforceable. Without any specific comments to address, the SDT is unable to further address your concerns. No change made. 7. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 8. Based on your comment and those of others, the SDT has revised the definition of Year One. **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.				
David H. Boguslawski	Northeast Utilities	1	Negative	NU votes to oppose TPL-001-1 with the following comments: Northeast Utilities (NU) is very appreciative of the effort of the SDT in preparing TPL-001-1. NU believes that this effort has resulted in a new TPL standard that shows improvement over the existing TPL standards. However, there are still some important concerns that NU believes should be addressed prior to the adoption of TPL-001-1. Therefore, in its present state NU can not vote for the acceptance of the draft standard and votes to REJECT the proposed standard (TPL-001-1). NU would like the SDT to re-visit and address the concerns listed below: 1. The use of Non-Consequential Load Loss to mitigate violations arising from certain planning events: NU has objected to this requirement in comments submitted for previous drafts of TPL-001-1. NU believes that Non-Consequential Load Loss should not be considered for P1 to P7 events to achieve the level of reliability needed when planning the electric power system. The amount of load that could be shed is open ended in TPL-001-1 and this will lead to different interpretations which can be detrimental to the stakeholders. To put it simply the standard as currently drafted will lead to

Voter	Entity	Segment	Vote	Comment
				confusion as Transmission Owners, Regional Reliability Organizations, along with state and federal agencies will need to come to agreement on what the standard allows and what it doesn't. Ultimately, a standard that does not have clear measurable criteria will lead to difficulty in developing and obtaining approval for projects to achieve the required level of reliability. If the SDT and NERC believe that allowing the use of Non-Consequential Load Loss for multiple element contingencies (e.g., N-1-1 or P6 planning events) is necessary in achieving system reliability then NERC should specify that the amount should be minimal, such as less than 100 MW. 2. The use of past study reports to satisfy Requirement R2, parts R2.1 and R2.2: The language of Requirement R2, parts R2.1, R2.2 and R2.6 is confusing and will lead to different interpretations from different stakeholders. While Requirements R2.1 and R2.2 indicate that annual studies should be conducted and to be supplemented by past studies, Requirement R2.6 seems to suggest that past studies could be used instead. The SDT's response to NU's comment on this issue supports the assertion that annual studies should always be conducted even if there are no changes in the system conditions and past studies should be used for the years within the assessment period but not called out by the standard. If studies are conducted every year then why the need to use past studies. This creates unnecessary study work and should be changed. 3. Table 1 - Steady State & Stability Performance Planning Events, Category P5 Events: This requirement as currently worded goes well beyond the intent of the Standard Committee as stated in response to comments as follows: "A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event". It is NU's opinion that similar language to the comment response should be incorporated into this requirement to avoid any confusion. 4. Base case initial conditions: NU believes that a great deal of confusion and uncertainty will be eliminated or reduced if the standard attempts to define the nature of initial base cases that should be used in planning studies. As it stands now this issue is left to interpretation, which can lead to confusion when determining appropriate planning projects to achieve a reliable power system. Depending upon the interpretation of the base case dispatches and the level of interface flows (level of stress) they may reveal reliability violations in the power system. Non-uniformity in developing base cases for an area or region may mask real reliability problems in the system. This is one of the primary weaknesses of the existing TPL standards. 5. Items 1, 2, 3 and 4 are Northeast Utilities primary concerns which should be addressed prior to NU accepting the standard. NU has additional reservations about the standard that should be addressed in subsequent revisions. 6. NU also supports the comments from other transmission owners that 60 months may not be

Voter	Entity	Segment	Vote	Comment
				sufficient to complete construction of transmission facilities.

Response: 1. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others' concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

2. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

Requirement R2 - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Requirement R2, part 2.1 - The Near-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, as follows:

3. The SDT has changed the text for the P5 event as a result of your (and others') comments to address these concerns.

P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

4. The SDT is trying to provide guidance without being overly prescriptive. Projected System conditions as well as the types of sensitivities that need to be studied are described. No change made.

5. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.

6. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. ince problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Henry G. Masti	New York State Electric & Gas Corp.	1	Negative	NYSEG supports the NYISO comments and also offer: The standard requires that dynamic load models be used that take into account induction motor effects. This information is generally not available and therefore it would be unworkable to develop an accurate model. The standard requires relays be modeled into the dynamic simulation. While standard mho, distance, or reactance distance relay model may exist, manufacturer-specific relay models often do not. Since this modeling is generally not available, it would be unworkable to develop an accurate dynamic model to test relay loadabilitiy.

Voter	Entity	Segment	Vote	Comment
Response: The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific so this is not unworkable. No change made. The SDT has clarified Requirement R4, part 4.3.1, bullet #3 to address your concerns. **Requirement R4, part 4.3.1 -** 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: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Negative	Oklahoma Gas & Electric (OG&E) Comments on Proposed NERC TPL-001-1 1.) OG&E feels that the effective dates of R1 and R7 shall become effective 18 months and not 12 months. Some entities budgeting cycles may not be based on 12 months and expenditures may be required by some to be compliant. 2.) OG&E feels that the effective dates of R2 through R6 shall become effective 30 months and not 24 months. This will allow entities adequate time to budget (personnel & tools), train, and perform the required studies. 3.) As others have mentioned, OG&E would like the 60 months extended to 84 months. 4.) Further examination should be conducted to evaluate the feasibility of performing the stability analysis every two years and not annually. 5.) OG&E has concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. 6.) The abbreviations of HV and EHV used in Table 1 shall be defined in the "Definitions of Terms Used in Standard" section. 7.) Although Table 1 has been improved, further work is needed to make Table 1 more intuitive. The notes at the beginning and ending of Table 1 seem awkward within the document.
Response: 1. The SDT believes that 12 months is sufficient. This isn't a completely new requirement – entities should be doing this work now for the existing TPL				

Voter	Entity	Segment	Vote	Comment
standards. No change made. 2. The SDT believes that 24 months is sufficient. This isn't a completely new requirement – entities should be doing this work now for the existing TPL standards. No change made. 3. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 4. The requirement is for an annual assessment and past studies can be used if qualified as per Requirement R2, part 2.6. No change made. 5. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made. 6. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. 7. Without any specific comments to address, the SDT is unable to further address your concerns. No change made.				
Mark Sampson	PacifiCorp	1	Negative	PacifiCorp appreciates the diligence and dedication of the Standard Drafting Team and commends the group for their hard work to bring the proposed standard TPL-001-1 to this level. PacifiCorp believes the overall language of the standard has improved to enhance its readability and the language and format of the Tables now provides some improvement in the understanding of acceptable System performance for the various Planning Events. However, inasmuch as the proposed Standard has improved, we cannot support the approval of this document at this time. The following comments and suggestions are provided in support of a no vote on the TPL-001-1 standard as currently proposed proposed. 1) As currently written our Company does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Building a transmission line in PacifiCorp's 6 state service areas varies significantly in regional and local planning and review process, permitting, siting, legal challenges, routing, and system path rating process can often take more than 5 years to complete from the time the project is authorized. Though requirement R2.7.3 is included to address situations beyond the control of the Transmission Planner, it leaves to the interpretation of the auditor whether the appropriate actions are being taken to resolve the issue that would continue to allow dropping of Non-Consequential Load or curtailment of Firm Transmission Service. Table 1 - Steady State & Stability Performance Planning Events Category P2 (Single Contingency). Category P2 requires responsible entities to study the opening of a line section without a fault. The standard as written states that the opening of this line section will not result in consequential load
John Apperson	PacifiCorp	3	Negative	
Sandra L. Shaffer	PacifiCorp	5	Negative	
Gregory D Maxfield	PacifiCorp	6	Negative	

Voter	Entity	Segment	Vote	Comment
				loss and no voltage or thermal violations will occur on the BES. . This requirement is applicable to EHV (above 300 kV) and HV (100-300 kV) facilities. PacifiCorp believes that this requirement should not be applicable to all HV facilities. From a reliability perspective, a more effective and efficient method would be a bifurcated functional requirement rather than a voltage requirement. In PacifiCorp's system, and in much of the Western Interconnection, a breaker that opens without a fault in the 115/138 kV system almost never has the potential to cause impacts beyond the local area. In most cases this extremely rare event (the unplanned opening of a breaker without a fault) cannot impact the EHV Bulk Electric System. As such, this requirement (P2-1) is not appropriate at the HV voltage levels. A more appropriate requirement for P2-1 would be to require this performance level only for the EHV portion of the BES and the HV facilities that perform a transmission service in addition to local load service. This should not be a requirement for HV facilities that only provide local load service. 2) Table 1-P5 Multiple Contingencies (Fault plus Protection System failure to operate) Normal System. There is a significant change in the system normal performance required for EHV systems from the current performance required in TPL-003 (Category C). This TPL-001-1 version does not allow any Non-Consequential load loss (table 1) or firm Demand (note 9) for EHV systems in the event of protection system failure and delayed clearing. This performance requirement would thus preclude use of existing protection systems that rely on remote clearing of interconnected EHV lines or stations if they provide local load service. As written the standard essentially now requires Category B performance rather than Category C performance for multiple contingencies. It is PacifiCorp's opinion that loss of Non-Consequential load or firm Demand should be allowed for the rare event involving multiple contingencies stated in P5 as long at the load or firm Demand loss is contained and controlled in the local load service area and the event does not impact other interconnected utilities or their loads. 3) Table 1 - Steady State & Stability Performance Planning Events Category P5 (Multiple Contingency (Fault plus Protection System failure to operate). Category P5 requires responsible entities to study the Event titled Failure of a single Protection System that results in Delayed Fault Clearing on one of the following: Generator, Transmission Circuit, Transformer, Shunt Device, or Bus Section. It appears that this requirement is an indication that multiple protection system failure is not allowed under the proposed TPL-001-1. This appears to be a requirement for redundant protection systems for all possible events on all voltage levels of the transmission system. It also appears that this requirement is attempting to define what comprises an adequate protection system. As the draft standard is presently written it appears that multiple protection system failures are not included in this part or any part of the draft TPL-001-1 standard. As written, it is PacifiCorp's view that any multiple protection system failure would be categorized as an Extreme Event under the draft TPL-001-1

Voter	Entity	Segment	Vote	Comment
				standard. PacifiCorp contends that the many and varied issues associated with designing appropriate protection systems should be done in the context of the development of a protection system standard and not in the context of TPL-001-1. In fact, there is currently a proposed standard going through the NERC standards development process which goal is exactly that. If the standards drafting team intends to require responsible entities to have 100% redundant protection systems on all of its BES facilities, PacifiCorp contends that this fact should be stated up front in the standard so that all interested parties may become aware of this requirement and provide informed comment. PacifiCorp believes that it is appropriate to wait until the current protection system redundancy standard under development proceeds through the SAR process and approval system, given that this in an important generic issue that affects the entire industry. Notwithstanding the inappropriateness of raising the protection system issue in the context of a planning standard, PacifiCorp believes that any planning requirement that includes the failure of a single protection system that results in delayed fault clearing must have a very clear definition of the terms “single protection system” and “delayed fault clearing” in or for entities to determine what compliance with the standard requires. The draft TPL-001-1 standard does not have clear definitions of these terms, leaving room for considerable latitude for interpretation by various responsible entities, auditors, and compliance enforcement authorities. Clear, specific, and technically defensible language is needed for these terms. 4) As drafted the standard TPL-001-1 has added requirement 2.1.5 discussing spare equipment and lead times and inclusion in the “Planning Assessment”. The standard in this section is not performance based requirement but an activity based requirement as currently stated under R2 2.1.5. PacifiCorp recommends that the standard should be revised and 2.1.5 removed as it does not directly improve the systems performance requirements nor compliance stated in Table 1.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others’) suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.

The SDT believes that the addition of footnote 12 (when it is finalized) will address your concern.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

Voter	Entity	Segment	Vote	Comment
P5. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94). The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment				
John C. Collins	Platte River Power Authority	1	Negative	Platte River appreciates the efforts and perseverance of the Drafting Team on this important standard. A "no" vote is cast because the following requirements are not clear and have RISKS for different interpretations that could result in non-compliance. (1) Table 1 Planning Events, column for Initial System Condition. Does "Loss of" refer to a planned outage or forced outage? (2) Table 1, Extreme Events, column for Stability. In Stability Event 1, what is the fault type for the first forced outage? (The second forced outage is specified as 3-phase.) (3) Contingency lists required for Planning Events in Table 1. The required scope of contingency analysis for each Category is not clear. P1. Create a list of Contingencies only for the more severe P1 type, or create lists for each of P1-1 through P1-5 types? P2. Create a list of Contingencies only for the more severe P2 type, or create lists for each of P2-1 through P2-4 types? P3. Create a list of Contingencies only for the more severe P3 type, or create lists for each of P3-1 through P3-5 types? P4. Create a list of Contingencies only for the more severe P4 type, or create lists for each of P4-1 through P4-6 types? P5. Create a list of Contingencies only for the more severe P5 type, or create lists for each of P5-1 through P5-5 types? P6. Create a list of Contingencies only for the more severe P6 type, or create lists for each of P6-1-1 through P6-4-4 types, 16 possible combinations? P7. Create a list of Contingencies only for the more severe P7 type, or create lists for each of P7-1 through P7-2 types? (4) Contingency lists required for Extreme Events in Table 1. The required scope of contingency analysis for each Steady State and Stability columns is not clear. Create a list of Contingencies only for the more severe type, or create lists for each of the "such as" types? (5) Table 1, compare footnotes 1, 3, and 5. Does a P4-3 or P5-3 contingency involving an EHV-HV transformer and causing deficiencies on the EHV allow Non-Consequential Load Loss to correct since

Voter	Entity	Segment	Vote	Comment
				the HV is the lowest voltage and override the "No" in the column for Non-Consequential Load Loss Allowed for EHV? (6) What is a "sufficient amount" and how much is a "measurable change" for sensitivity case stressing? See parts 2.1.4 and 2.4.3. (7) Are the actions associated with single vs. multiple sensitivity studies in part 2.7.2 Corrective Action Plans? (8) Are Long-term stability analyses required only if there are generation additions or changes in the long-term horizon? See part 2.5.
Response: 1. Planned outages of six months or more should be incorporated into the P0 condition as per the requirements. The events cited are forced outages. 2. It doesn't matter what type of Fault creates the first outage condition as it is the second outage that is studied. 3. The SDT believes that an entity only needs a list for those types of events that are more severe for your study area. 4. An entity doesn't need a list for each 'such as'. The rationale for those selected must be documented as stated in the requirements. 5. For an outage of an EHV/HV transformer, performance requirements specified as HV must be met. 6. Requirement R2, part 2.1.4 is part of Requirement R2 which mandates that an entity must document all assumptions utilized in the Planning Assessment. No change made. 7. Requirement R2, part 2.7.2 is for multiple sensitivities. Requirement R2, part 2.7 states that Corrective Action Plans are not required for single sensitivities. 8. Yes, it is required only if there are additions or changes in the long term.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	Reword Table 1 Note (i) as follows: The response of voltage sensitive load that is disconnected from the system by end-user equipment associated with an event shall not be used to meet steady state performance requirements Reword Requirement R 1.1.5 as follows: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Negative	
Peter T Yost	Consolidated Edison Co. of New York	3	Negative	

Voter	Entity	Segment	Vote	Comment
Response: The header note is not just for disconnections by end-user equipment but would also cover the natural response of Load for voltage reduction. The suggested wording changes the intent of the SDT. No change made. The SDT believes that the defined term 'Interchange' covers other transfers as described in your comment. No change made.				
Henry Delk, Jr.	SCE&G	1	Negative	SCE&G appreciates the efforts of the Standard Drafting Team and believes this version of the TPL standard has addressed most of the significant issues found in previous versions. However, SCE&G believes there are several significant issues that need modification or further explanation. 1. SCE&G agrees with other submitted comments that the requirement to complete new transmission construction to meet new performance requirements within 60 months is too short. SCE&G believes that 84 months is more reasonable. 2. SCE&G agrees with comments submitted by Duke Energy that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability and service quality. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. 3. SCE&G believes there are still different interpretations of Consequential and Non-Consequential Load loss and how each should be applied or not applied. The Standard drafting team should provide several examples in its response to these comments showing how to apply and not apply Consequential and Non-Consequential Load Loss. Without clear examples, SCE&G believes many request for interpretation will be submitted to NERC by the industry.
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. The SDT has clarified the issue of Non-Consequential Load Loss as shown above. Providing examples here of what is Non-Consequential Load Loss versus				

Voter	Entity	Segment	Vote	Comment
Consequential Load Loss would have no bearing on eventual compliance findings. The words are what matter and the SDT feels that the clarification provided should alleviate your concern.				
Charles H Yeung	Southwest Power Pool	2	Negative	SPP recommends the standards drafting team review the IRC SRC comments submitted in Oct 2009 and reassess those concerns.
Response: The SDT addressed the comments of the IRC SRC in its responses to the last posting which were captured in the Consideration of Comments report. Without any new specific comments to address, the SDT is unable to further address your concerns. No change made.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	SWTC Comments: The SDT has done a lot of good work in developing the TPL 001 standard. However, I agree with the comments of others and suggest that another draft should be produced before the standard is sent to a ballot. SWTC forsees a problem with manpower and the cost of studies for small entities such as ourselves. This will be an extra burden and costs that will ultimately be borne by the consumer who is already not very happy lately. In part 2.7.1, remove the second sentence and all bullets. These are not measurable performance criteria. EHV" and "HV" need to be defined because they are not defined in the NERC Glossary. R4.3.2 This is an admirable goal, and we applaud the SDT's vision. However, modeling all Protection Systems may be beyond the capabilities of presently used dynamic modeling tools. The number of impedance and overcurrent relays that would need to be included for lines and transformers would likely overwhelm these programs. We are concerned that the programs in use may not have the capability to model important relay characteristics such as load encroachment or out-of-step operating characteristics. R5 & R6: Shouldn't the Load Serving Entities (LSEs) define system performance criteria instead of the Transmission Planner or the Planning Coordinator? The LSEs have an obligation to their customers and must demonstrate to their regulators that they are providing acceptable system performance and reliability of supply to their customers. The Transmission Planner and Planning Coordinator have less incentive to provide high levels of system performance. Due to regulatory difficulties in getting approvals for transmission system upgrades, there may be a tendency on the part of TPs and TCs to avoid proposing transmission upgrades, letting system performance degrade instead by abandoning traditional planning criteria and defining less stringent standards for themselves. R6 Remove the "for conditions such as ..." list.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has clarified Requirement R2 and part 2.1 to make it clearer that qualified past studies can be utilized. **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. **Requirement R2, part 2.1 -** The Near-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, as follows: The listed items are simply that – a list of actions that would be included. This is an allowable and encouraged format for Reliability Standards. No change made. The EHV/HV differentiation is not meant to be a definition in that it only applies to this standard. No change made. The SDT believes that your comment is for Requirement R4, part 4.3.3. The SDT has modified the wording of this requirement to address your concern. **Requirement R4, part 4.3.1 -** 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: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. These are System requirements for the BES and properly belong to the Planning Coordinator and Transmission Planner. No change made.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	The Bonneville Power Administration (BPA) acknowledges and appreciates the hard work and diligence of the Standards Drafting team on such a large effort. BPA respectfully submits the following comments.

Voter	Entity	Segment	Vote	Comment
Rebecca Berdahl	Bonneville Power Administration	3	Negative	1. Requirement R1.1.2: BPA recommends that system models should only represent outages with a duration of one year or more. The planning horizon should not cover an outage less than one year because there is not adequate time for developing and implementing any necessary mitigation plan. Known outages with duration less than one year should be dealt with in the Operations horizon. In addition, the near term steady state studies represent year one or year two and year five as required by R2.1.1. Therefore it is not consistent with the rest of the standard to require modeling outages less than one year. 2. Requirement R3.5: BPA recommends removing the requirement to evaluate possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme events. o This is more stringent than the existing requirement without providing any increased reliability benefit. The new standard already requires a significant increase of study cases and this additional requirement results in an undue study burden on utilities without adding any benefit. o In addition, Table 1, Extreme Events, should be reduced to a more prudent list of possible events to evaluate risks and consequences. It is obvious that several of the events, especially under item 3 (Wide Area Events), would cause cascading and it is not practical to evaluate possible mitigation plans for such extreme events. 3. Table 1: The category P2 Single Contingency should be removed. o Events P2.2, P2.3 and P2.4 should be moved to category P4 since these events are not single contingencies. P2 is a single contingency category, which by definition takes one system component out of service. Bus section faults and bus-tie breaker faults are multiple contingencies since they are events that take multiple system components out of service. o Event P2.1 “opening of a line section w/o a fault” should not be included in the planning standard. At a minimum Event P2.1 should be moved to Category P1 since it is a single contingency and it should allow Interruption of Firm Transmission Service and Non-Consequential Load Loss for the HV ((<300 kV) BES level. Many of the HV (115-kV) lines have taps that serve loads and are designed to remove all elements that the protection system and other automatic controls are expected to disconnect. This is consistent with Requirement 3.3.1 which states “Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.” Inadvertent opening of one end of an HV line section without a fault almost never has the potential to cause impacts beyond the local area, yet has a low probability of occurrence and would be very costly in some cases to mitigate. 4. Footnote 11: BPA recommends removing the reference to common Right-of-Way. This could be mis-interpreted that a common Right-of-Way longer than 1mile should be planned for under Category
Francis J. Halpin	Bonneville Power Administration	5	Negative	
Brenda S. Anderson	Bonneville Power Administration	6	Negative	

Voter	Entity	Segment	Vote	Comment
				P7. The NERC standards only include common Right-of-Way under extreme events and in this footnote. So, it would be consistent with the rest of the standard to remove this reference from the footnote and possibly make a specific reference in the Extreme Events category where it applies. 5. Requirement R2.4.1: BPA agrees with other commenter's concerns that requiring Load models that consider the behavior of induction motor Loads is premature without adequate development and benchmarking efforts. In addition, specific types of models and data required for analysis should not be mentioned here, but should be specified and submitted through the appropriate MOD Standard's. 6. Requirement R4.3.3: BPA agrees with other commenter's concerns regarding simulating the impact of transient swings on Protection System operation for Transmission lines and transformers. It would be an extremely burdensome task to model relay impedance characteristics for all elements with little or no benefit, and it is questionable whether the simulation programs would support this effort.

Response: 1. The time frame is for future outages in the planning horizon and last for at least six months. No change made.

2. The SDT disagrees as this is effectively the same requirement as presently stated in TPL-004. No change made.

The SDT does not agree that these conditions obviously will create Cascading. The SDT reminds the commenter that not all events must be studied. No change made.

3. The category descriptions are meant to characterize the events. A single event may remove more than one element from service and that has been addressed in Header note 'c'. The SDT does not believe that there are inconsistencies within the table. The P2 category describes single events that may result in multiple elements being removed from service. The P2 events differ from the multiple event categories which consider two or more sequential events. No change made.

4. The SDT has revised the footnote to provide additional clarity based on your comment.

> **11.** Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

5. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. No change made.

6. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** 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:
>
> - Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
> - Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
> - Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual

Voter	Entity	Segment	Vote	Comment
relay models.				
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	The Empire District Electric Company appreciates the dedication of the Standards Drafting Team Empire cannot support the approval of the proposed standard as written. Empire finds exception to the proposed standards in the following areas: 1) We disagree with the proposed requirement 2.1.5 on spare equipment strategy in that it is discriminatory for smaller entities like Empire. Having a spare transformer is not practical and makes far less sense for a smaller entity but yet has a significant rate impact to our customers. 2) We disagree with requirement 3.3.3 as written would require modeling of nearly every phase distance relay, especially when studying extreme events. The requirement deserves flexibility as allowed in requirement 3.3.2 3) We do not believe 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. Our suggestion to the drafting team would be some amount of time greater than 7 years (84 months).
Response: The SDT has clarified the requirement based on your comments and those of others. **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.				

Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Negative	The Florida Municipal Power Agency (FMPA) appreciates the hard work of the SDT, but, we believe there are significant issues that remain with the standard. FMPA believes that 5 years is not enough time to build significant new transmission lines and believes that 7 years is a more appropriate lead time. FMPA believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local quality of service issues and does not provide any real benefit to BES reliability. The standard ought to separate what an entity chooses to do for the benefit of its own customers and the impacts it may on the reliability of the BES. FMPA believes that an entity has the right to choose to utilize the existing footnote "b" in the version 0 standards if that choice does not detrimentally impact the ability to provide transmission service to others. FMPA believes that requirement 2.1.5 on spare equipment strategy is discriminatory to smaller entities. Also, Order 693 at Paragraph 1725 states: "... the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy". The standard oversteps this direction by not including a consideration of planned outages versus forced outages. Requirements 3.3.3 and 4.3.1 would require modeling of nearly every phase distance relay in the Interconnection. It is questionable whether we have the software tools to do so, and this would require a huge level of effort to maintain an interconnection wide database of relay settings for questionable benefit. FMPA believes that the SDT ought to evaluate the perceived increase in accuracy that is intended with these requirements. It is FMPA's belief that the expected increase in accuracy is lost when considering other simulation inaccuracies that we really cannot improve (e.g., load modeling) until much more work is done on improving our understanding of dynamic load behavior and benchmarking the model to actual system events.

Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has clarified the requirement based on your comments and those of others.

Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a

Voter	Entity	Segment	Vote	Comment
lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment The SDT agrees that a planner should be able to utilize conservative assumptions and screening methods and doesn't believe that there is anything in the requirement that precludes an entity from doing so. No change made. The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern. **Requirement R4, part 4.3.1 -** 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: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Alden Briggs	New Brunswick System Operator	2	Negative	The NBSO applauds the efforts of the Drafting Team on this very important TPL standard. However, we feel that it is not quit ready for acceptance but with a few tweeks and some much needed clarity it would be. NBSO believes the BES versus BPS needs resolution as we much prefer standards that applicable to the bulk power system based on an impact assessment opposed to an arbitrary voltage level. The standard should be more flexible allowing for any trade off between temporarily shedding small amounts of load to recover from a single contingency where the alternative which may force significant transmission upgrades. The standard gives preference to a single line feeding a local area versus two lines, where the loss of one of two under high loading conditions should allow for portions of load to be shed to maintain voltage. The standard considers demand side management as an option but no allowance for instantaneous and temporary load loss that could be required before DSM could be activated. The standard should be clear that if in agreement with a distribution provider some portions of the distribution load (non-consequential load loss) may be shed for a single contingency for undervoltage and underfrequency conditions. The requirements for load models should be clarified so capture dynamic behaviour within reason.

Voter	Entity	Segment	Vote	Comment
				There should be a Q&A guide to allow for examples to clarify the requirements.

Response: The SDT does not believe that it needs to define BES. In its March 18th order, FERC suggested a continent-wide definition of the BES. No change made.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

DSM is permitted because it is pre-arranged with the customer. For transmission systems, DSM is expected to be used in anticipation of the next transmission system Contingency, not in response to the transmission system Contingency. UVLS & UFLS are intended safety nets for operations and should not be relied upon in transmission planning. No change made.

The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.

While a Q&A providing examples may be helpful it would have no official bearing and such an effort is not in the project schedule.

Voter	Entity	Segment	Vote	Comment
Gregory Campoli	New York Independent System Operator	2	Negative	The New York Independent System Operator (NYISO) believes this proposed standard is moving in the right direction with the right intentions, and while we truly appreciate the expertise and hard work that the standards drafting team (SDT) has consistently exhibited throughout this lengthy process, we have voted no on the adoption of this balloted version of the proposed NERC Standard TPL-001-1 for the following reasons: 1. The proposed Standard would significantly, and unnecessarily, shift responsibilities away from the Transmission Owner (TO). The proposal would require that for the Bulk Electric System (BES) throughout the New York Control Area (NYCA) the NYISO would annually evaluate: specified contingency events, all corrective action plans, and all spare equipment strategies. As we are not a BES facility owner, we believe that facility specific requirements should stay with facility owners. 2. The proposed Standard requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include…” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. 3. The proposed Standard would require the PC & TP to assess the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but

Voter	Entity	Segment	Vote	Comment
				provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). 4. The proposed Standard would require an "annual" assessment of the system in order for it to be considered "current." The NYISO has a biennial reliability planning process and does not find it necessary to perform all studies annually in order to be current. We see no reliability benefit to requiring this to be done annually; in fact, dilution of planning efforts and resources is in itself a reliability risk. 5. The proposed Standard lacks a clear definition of the first year of the planning horizon. It is defined as the planning window that begins 12-18 months from the end of the current calendar year. If "Year One" is two calendar years out, what is year two? year five? This ambiguity poses an unacceptable risk to compliance. 6. For steady-state and stability analysis, the proposed Standard creates a limited list of required sensitivities, and may require sensitivities with no useful objective. The Standard should instead provide a list of suggested sensitivities to allow the planning entity to use its judgment to study sensitivities pertinent to its system. Furthermore, in the absence of a definition of base case conditions, it is difficult to determine, from a compliance standpoint, what is a "stressed" system. 7. The proposed Standard requires stability models to represent the dynamic behavior of loads, including the consideration of the behavior of induction motor loads. 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 this requirement being in place, a modeling standard should exist that is specific to dynamic loads.

Response: 1. Planning the system is the responsibility of the Planning Coordinator and Transmission Planner as per the Functional Model. The Planning Coordinator or Transmission Planner simply needs to account for those strategies and facility specific items that are passed to them by asset owners. No change made.

2. The list is not all inconclusive but a list of possible actions. The SDT agrees that runback or tripping of HVDC would be allowable actions. No change made.

3. The SDT has clarified the requirement based on your comments and those of others.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment

4. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words

Voter	Entity	Segment	Vote	Comment

may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2** - Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

> **Requirement R2, part 2.1 -** The Near-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, as follows:

5. Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

6. The SDT has made clarifying changes to Requirements R1 and R2, part 2.1.4 to address your concerns.

> **Requirement R1 -** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes the normal system condition in Table 1.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance:

7. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made.

Voter	Entity	Segment	Vote	Comment
Alan Adamson	New York State Reliability Council	10	Negative	The New York State Reliability Council (NYSRC) appreciates the hard work and time the drafting team has devoted during its preparation this standard. The present version represents a significant improvement over the present transmission planning TPL standards. However, the TPL-001-1 standard needs further improvement in several areas before the NYSRC can vote to approve the standard, as follows: 1. The standard requires annual assessment of the system regardless of whether system conditions are essentially unchanged from year to year. This may require unnecessary study work. 2. Testing requirements are rigidly defined in the standard, but specifically what is to be tested is loosely defined. 3. The standard requires analyses of a specific list of sensitivities. Instead, the standard should provide a list of suggested sensitivities and allow the planning entity to use its judgment to study those sensitivities that may be more pertinent to its system. 4. The standard requires stability models to represent the dynamic behavior of loads, considering the behavior of induction motor loads. New York has not modeled dynamic loads, and such modeling has never been benchmarked. For many years, simulations of actual system disturbances have been represented with excellent accuracy, without modeling loads dynamically. 5. The definition of BES (100kv bright line) is uncertain at this time. Therefore, until this definition and its application is resolved, it is not possible to know - without a clarifying provision in the standard - which portion of a system that presently has a performance based methodology, such as the New York State Power System, is subject to the TPL-001-1 standard.

Response: 1. The intent of the SDT wasn't that annual studies are required but that an annual Planning Assessment is required. However, the SDT agrees that the words may have been somewhat confusing. Therefore, the SDT has clarified the wording of Requirement R2 and part 2.1.

> **Requirement R2 -** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

> **Requirement R2, part 2.1 -** The Near-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, as follows:

2. What needs to be tested is the transmission system that is under the purview of the Planning Coordinator or Transmission Planner.

3. The SDT has made clarifying changes to Requirement R2, part 2.1.4 to address your concerns.

> **Requirement R2, part 2.1.4 -** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to

Voter	Entity	Segment	Vote	Comment
demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment 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 performance: 4. The SDT assumes that you are referring to the induction motor Load modeling required for Stability studies. The standard permits an aggregate model assumption that can be applied for a given system that is not substation specific. Dynamic load modeling is important for correct dynamic simulations. Industry has acknowledged the need for accurate Load modeling and the SDT has codified this need in the proposed standard. No change made. 5. The SDT does not believe that it needs to define BES. In its March 18th orders, FERC suggested a continent-wide definition of BES. No change made.				
James Armke	Austin Energy	1	Negative	The proposed TPL-001-1 Standard needs to be revised regarding the comments submitted by Ameren, Duke, and JEA.
Response: Please see responses to Ameren, Duke, and JEA.				
Silvia P Mitchell	Florida Power & Light Co.	6	Negative	The SDT has addressed many of the gray areas of Draft four in their consideration of comments however these comments are not part of the Standard that is currently out for ballot. Incorporating these type of clarifying comments in the Standard with the use of footnotes to clarify the intent would be a significant improvement for anyone interpreting the Standard including an auditor or investigator. The definition of Year One is an unnecessary departure from the planning practices used in most of the Eastern Interconnection. It is recommended the phrase end of the current calendar year be changed to the current calendar year. This change will allow PAs to begin their near term analysis with either next year or the year after as deemed appropriate. The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Absent this, the 60 calendar month phase in period described in the Introduction section is too short for transmission facilities rated above 300 kV. Approval and permitting of EHV transmission lines is

Voter	Entity	Segment	Vote	Comment
				extremely difficult and time consuming in most parts of the Eastern Interconnection. The phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counterproductive. Requirement 2.5 represents a significant expansion of Stability Studies into the Long Term horizon. In many cases the stability issue in long term scenarios will be with the response of new generating plants to fault scenarios such as a breaker failure event. The protection upgrades needed to mitigate performance issues are easily accomplished in the short term. The uncertainty of compliance judgment of rationale documentation will force a tremendous amount of unnecessary study work. It is recommend Requirement 2.5 be removed. We concur with the SDT's opinion expressed in the most recent consideration of comments that the individual component level evaluation of protection systems and redundancy requirements should be covered under the PRC standards and that the intent of the protection failure contingencies specified in Table 1 is to simulation the failure of a single protection scheme. The event description for the P5 contingency was revised in draft 5 but it continues to reflect a range of protection component failures that greatly exceed the intent of the SDT. The term Protection System is in direct conflict with the intent of the SDT, as it is defined in the Glossary to include components such as station batteries. The term Protection System should be replaced with Protection Scheme in Table 1. Requirement 4.3.1 can be interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; Simulate the operation of Protection Systems and other automatic controls as they would be expected for each contingency. The SDT has indicated in their responses to previous comments on requirement R4.3.3 that generic relay models could be used for screening purposes. While we agree with this as a practical method,

Voter	Entity	Segment	Vote	Comment
				the language of R4.3.3 could be interpreted to require explicit modeling of all protection and controls which is neither practicable nor an effective use of engineering resources. It is recommended that R4.3.3 be deleted.

Response: The SDT has made every attempt to fully clarify the intent of the requirements in response to official specific comments. Without specific references, the SDT is unable to act on your comment. No change made.

Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

Material change is system specific and difficult to define on a continent-wide basis and is left to engineering judgment with a documented technical rationale as stated in the requirement. No change made.

The SDT has clarified Requirement R2, part 2.5 to address your concerns.

> **Requirement R2, part 2.5 -** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part2.6. The technical rationale for determining material changes shall be documented.

The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns.

> **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following:
>
> **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

> **Requirement R4, part 4.3.1 -** 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:

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
4.3.3 - The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

Requirement R4, part 4.3.1 - 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:
Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.</td></tr>
<tr><td>Christopher Plantev</td><td>Integrys Energy Group, Inc.</td><td>4</td><td>Negative</td><td>The Standard is moving in the right direction, but the following concern is preventing us from voting “affirmative”. The timeframe of 60-months (5 year) for implementing Corrective Action Plans (CAP), is insufficient. We believe that the implementation timeframe must be extended to seven (7) years.

Requirement 2.7.3, which covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but the proposed language is ambiguous. An auditor could identify many things that could reasonably be within the “control” of a TP or PC but are not covered by NERC standards or a TP / PC’s process, procedures or criteria. This discretion leaves entities open to possible non-compliance violation based on an auditor’s perception of what they believe should be in the TP / PC’s control. In addition, the concept of “control” must be limited to an entities' compliance obligation as a Transmission Planner and/or Planning Coordinator. In other words entities must be allowed the ability identify situations which fall under its “control” as a Transmission Owner, Transmission Operator, Generator Owner or Generator Operator etc. but is beyond the responsibility of its Transmission Planner or Planning Coordinator functions.</td></tr>
<tr><td colspan="5">Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others’) suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility. If an entity can demonstrate that it has made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
Thomas J Trickey	Lakeland Electric	5	Negative	The timeframe of 60-month (5 year) for implementing Corrective Action Plans (CAP), is insufficient, recomend that the implementation timeframe be extended to seven (7) years.
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.				
Greg Lange	Public Utility District No. 2 of Grant County	3	Negative	There appears to be many questions about the correct planning long-term horizon. This alone is enough to vote no and ask the drafting team to reconsider that language and their thought process. Grant also has an issue with section 2.1.5. We are struggling with the phrase "major Transmission equipment" and the example of "a transformer". We think it is very important for equipment that is necessary for bulk transfers on the system or one that if lost would cause harm to a neighboring system to be considered in this planning standard. We don't believe a BPS standard should force prescriptive behavior onto an entity, for customer service issues. If the loss of a transformer only impacts local load, this standard should not contemplate or prescribe what the local entity should do. This leaves to much interpretation up to the auditor. The standard could easily become. "You must have spare transformers in inventory to pass compliance with this requirement". Grant is aware that this standard in version zero addressed customer load. Shame on us for not being more proactive and correcting that issue then. We have a new opportunity to correct it now and we would like to see it done. This and all standards should leave local customer service issues alone and concentrate on performance of the major transfers between generation and large load centers. This is not to say that our utilites will choose to leave load off for a year, just that the decision for how to solve this local problem should remain local.
Response: The SDT is unaware of many questions being raised on the long term horizon. Without specific comments, the SDT is unable to address your concern. No change made. The SDT has clarified the requirement based on your comments and those of others.				

Voter	Entity	Segment	Vote	Comment
Requirement R2, part 2.1.5 - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment FERC has been quite clear that this standard needs to address the issue of Non-Consequential Load Loss. The SDT has added footnote 12 to address your concerns. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Mace Hunter	Lakeland Electric	3	Negative	There are two requirements in this Standard that could be interpreted in many different ways and will greatly complicate dynamic simulation studies. 4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing. 4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. Most problematic is 4.3.3 which can be interpreted as requiring discrete models of all relays protecting transmission lines and transformers. This is an impossible task. Developing explicit relay models for simulations of even a small subset of BES equipment would be an enormous engineering effort with little or no benefit. The SDT's response to this criticism is, "This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line." There are two problems with this response. First, if the SDT wishes to allow for the use of screening methods then this allowance needs to be part of the Standard language. The Standard development comments and responses have no standing once the Standard is approved by FERC as law. A narrow, strict interpretation of the Standard based on requirement language is to be expected from auditors and investigators. A second problem with the above SDT response is that applicability of generic models is subject to technical challenge. The generic model available within PSS/E sets up circular characteristics for each branch element that are fixed percentages of the branch impedance. These fixed, non adjustable percentages are 46% for zone A, 75% for zone B and 110% for zone C. These generic reaches are significantly smaller than loadability limits allowed under the PRC-023-1. The intent of Requirement 4.3.3 would be better served if reworded as follows; "R4.3.3 Consider the impact of dynamic swings on protection systems and model protection operation where appropriate" Requirement 4.3.1 can be

Voter	Entity	Segment	Vote	Comment
				interpreted to require dynamic simulation analysis of multiple fault event scenarios for transmission lines with high speed reclosing enabled. This additional analysis may be advisable for certain rare special situations but is unnecessary and burdensome as a general requirement for transmission planning contingency analysis. As such, requirement 4.3.1 will discourage application of high speed reclosing. This would be an unfortunate outcome given the benefits of high speed reclosing both for transmission reliability and customer power quality. It is recommended that 4.3.1 be reworded as follows; "4.3.1 Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency."

Response: The SDT has modified the requirement to address your concern.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

The SDT has revised Requirement R4, part 4.3.1, bullet #3 to address this concern.

Requirement R4, part 4.3.1 - 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:

- Successful high speed reclosing and unsuccessful high speed reclosing into a Fault.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Voter	Entity	Segment	Vote	Comment
Larry Akens	Tennessee Valley Authority	1	Negative	TVA appreciates the work of the ATFN drafting team over the last several years in drafting this new standard. TVA does have concerns on several issues that need to be corrected as we move forward with this standard. Therefore TVA is voting “Negative” on this proposed standard due to the following issues: 1. TVA believes that the 5 year implementation plan allowed for “Raising the bar” facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line is approximately 7 to 10 years, given the lead time on ROW and following all NEPA requirements. If the 5 year implementation plan is not increased, TVA is also concerned about the extensive outages that must take in upgrading 500-kV facilities in order to meet the 5 year requirement. This would require multiple 500-kV outages in the same timeframe which could have a detrimental effect on the overall Bulk Electric System reliability during this construction phase. TVA does understand that the team has added language regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no guarantee that TVA will be found compliant if all the work cannot be accomplished in this time frame. 2. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have no overall reliability gain for the Bulk Electric System. 3. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Additionally, R4.1.1 directly conflicts with Table 1, Note a (applicable to both Steady State & Stability) which states "Consequential Load as well as generation loss is acceptable as a consequence of any planning event … excluding P0." TVA strongly suggests that this loss of synchronism be allowed for P1 or at least add the ability to trip these units for this P1 event by out of step relaying - since other means of tripping the units are allowed - such as thru the use of other actions including Special Protection Schemes as long as the instability does not spread beyond a local area. 4. TVA is concerned with the inclusion of battery failures being included in event P5. P5 states “Multiple Contingency Fault plus Protection System failure to operate”. TVA understands that the drafting team believes that batteries are not intended to be included in this event; however, station batteries are presently included in the NERC Glossary definition of “Protection Systems.” TVA believes that specific language excluding batteries is required for this P5 event in order to prevent future compliance issues regarding this.
George T. Ballew	Tennessee Valley Authority	5	Negative	
Marjorie S. Parsons	Tennessee Valley Authority	6	Negative	

Voter	Entity	Segment	Vote	Comment
Response: 1. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. 2. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT believes that if an entity has a known condition that identifies a generation unit(s) is prone to trip for a single Contingency event then the entity should proactively trip the unit(s) rather than relying on out-of-step protection to trip the unit. The SDT takes this position because of the concern of the possible detrimental effects of loss of synchronism on the overall reliability of the BES. No change made. 4. The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Lee Schuster	Florida Power Corporation	3	Negative	We appreciate the challenging and time-consuming work that has been done by the Standard Drafting Team (SDT) to draft TPL-001-1 according to the specific requests made by FERC in Order 693. We are supportive of planning, constructing, operating and maintaining the most reliable Bulk Electric System (BES) that is reasonably feasible. We believe that collectively the industry has exhibited excellent BES reliability under existing NERC TPL Standards. For this reason and for others detailed below, we will vote "no" on the proposed standard. 1. We do not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. This is especially true of EHV projects. Ameren recently stated in an email to the RBB that "[b]uilding a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." In our own experience, we have been limited by permitting and local government processes to the extent that even 69 kV, 115 kV and 230 kV line projects are taking longer than 60 months. We therefore agree with Ameren's point that building of a new EHV transmission line can be a very lengthy process. We think that a more
Sam Waters	Progress Energy Carolinas	3	Negative	

Voter	Entity	Segment	Vote	Comment
Wayne Lewis	Progress Energy Carolinas	5	Negative	appropriate time frame would be 84 months, with provisions to limit or waive fines if a Transmission Owner can demonstrate that the implementation process was unavoidably impeded by permitting, environmental or governmental processes. 2. As has been stated in all four commenting periods by Progress as well as certain other registered entities, we believe that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach by the standard into local load quality of service issues that are already adequately regulated by states' Public Service/Utility Commissions, and does not provide any benefit to BES reliability. The approach of prohibiting the shedding of even a single distribution feeder amounts to feeder reliability rather than BES reliability. This approach, if allowed to be in the Standard, may result in unintended negative results in BES reliability. We therefore appeal to the SDT to discuss this issue with NERC and FERC given the numerous utilities that share this concern. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load. 3. Requirement R4.1.1 states in part that "for planning event P1: No generating unit shall pull out of synchronism." This requirement is overly burdensome without providing any material improvement in system reliability. Additionally, R4.1.1 directly conflicts with Table 1, Note (a) (applicable to both Steady State & Stability) which states "Consequential Load as well as generation loss is acceptable as a consequence of any planning event ... excluding P0." Clearly, the intent the TPL-001-1 standard is to maintain the integrity and reliability of the overall grid, not any particular element. In other words, throughout the standard it is acceptable to lose any generator, load, line or other element as long as more wide reaching consequences are precluded (i.e., cascading outages, non-consequential load loss, etc. is not allowed). As written, R4.1.1 would not allow the use of out of step protective relaying as a solution to trip an unstable generator for a P1 event. It does allow tripping of the same generator due to "fault clearing action" (such as for a fault on the generator terminals) or "by a Special Protection System". Therefore the loss of the generator itself must be acceptable. The notion that preventing loss of synchronism events is the only acceptable means of also precluding more widespread (and unacceptable) consequences resulting from the effect of stability swings is not valid. For some generating units (particularly small, remotely located units) these other unacceptable consequences may not even occur. Also, other means, such as out of step blocking of transmission lines applied in conjunction with out of step generator tripping, may be an effective solution. Any of these solutions is allowed for events P2 through P7 in requirement R4.1.2. We recommend that Requirement R4.1.1 be deleted and R.4.1.2 be revised to include events P1 through P7. Given the concerns raised above, we respectfully request that the SDT make the suggested improvements to TPL-001-1 and continue the process toward approval of the Standard.

Voter	Entity	Segment	Vote	Comment
Response: The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area. 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. 3. The SDT believes that if an entity has a known condition that identifies a generation unit(s) is prone to trip for a single Contingency event then the entity should proactively trip the unit(s) rather than relying on out-of-step protection to trip the unit. The SDT takes this position because of the concern of the possible detrimental effects of loss of synchronism on the overall reliability of the BES. No change made.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	We are voting negative for several reasons. 1. We believe Requirement 2, Part 2.1.5 is an administrative requirement that is not consistent with the NERC BOT approved results/performance based standards effort. Furthermore, the additional reliability benefit is not clear to us. 2. We believe that Requirement 2, Part 2.3 should only be implemented when there is another requirement in the PRC standards for Transmission Owners and Generation Owners to supply the necessary protection information. 3. We believe that that Requirement 2, Part 2.4.1 needs to be further clarified that the dynamic behavior of load model is an estimate only based on engineering assumptions. As written now, it is not clear how much deviation is allowed from actual system operation. 4. We believe Requirement 4, Part 4.3.2 should not be implemented until there is a requirement for the Generator Owners/Operators to supply their generator low voltage ride through capability. 5. We believe Requirement 4, Part 4.3.3 should be further refined to clarify that the purpose is to screen zone 3 relay issues. As written now, it appears that zone 3 relays must be modeled in detail because it is not clear that the intent is to only screen potential problems. We are basing our comments on the drafting team's responses to previous comments that they view using generic zone 3 relay models in PSS/E is acceptable.
Response: 1. The SDT disagrees that this is an administrative requirement as it does not state that you must develop a strategy; it states that you must consider the strategy in your planning. Therefore, it has a direct bearing on the reliability of the BES. No change made. 2. This standard describes what must be done and not how to do it. The SDT expects that the information cited could be obtained through several different				

Voter	Entity	Segment	Vote	Comment
mechanisms such as delegation agreements or data requests. No change made. 3. The SDT has added the word 'expected' to the text to alleviate your concern. Planning models are based on the best information available to the planners at the time of the study and it is well understood that they may not exactly represent actual conditions at any given time. The results of on-going benchmarking and model development activities can be incorporated when those activities yield more representative results. **Requirement R2, part 2.4.1** - System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. 4. This standard describes what must be done and not how to do it. The SDT expects that the information cited could be obtained through several different mechanisms such as delegation agreements or data requests. No change made. 5. In the summary considerations in draft 4 of this project, the SDT indicated that generic relay models can be applied. If this model shows impedance swings in a branch element, then one can either take action according to the generic model results or investigate the characteristics of the relays actually used on that branch. In this draft, the SDT has clarified the requirement for the use of generic relay models. **Requirement R4, part 4.3.1 -** 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: • Successful high speed reclosing and unsuccessful high speed reclosing into a Fault. • Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. • Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.				
Brenda L Truhe	PPL Electric Utilities Corp.	1	Negative	We are voting 'no' on this ballot as this revision proposes to expand contingency requirements beyond traditional planning levels (example - stuck breaker AND protection failure).
Mark A. Heimbach	PPL Generation LLC	5	Negative	
Response: The SDT agrees that new expectations are contained within the requirements aimed at improving BES reliability. An implementation plan has been created to allow for the industry to comply with the new requirements.				
Terry L. Blackwell	Santee Cooper	1	Negative	We disagree with the proposed definition of Year One. We believe that Year One should be the planning window that begins 12-18 months from the start of the current calendar year, and not from

Voter	Entity	Segment	Vote	Comment
Zack Dusenbury	Santee Cooper	3	Negative	the end of the calendar year. We believe that following this modification to the definition would require minimal adjustments to the ERAG MMWG model building process, which we all use as the basis for our planning models. Following the proposed definition would require additional models to be built by the MMWG or lead to holes in the model building effort for both the operating and planning horizons. SCPSA does not believe that 60 months is a reasonable time period to build transmission facilities to meet the new performance requirements. In an email to the registered ballot body, Ameren stated " Building a transmission line in Illinois is estimated to take 7 years (84 months) from the time the project is authorized." SCPSA agrees with the point that Ameren is making that building of a new EHV transmission line can be a very lengthy process. SCPSA thinks that a more appropriate time frame would be 84 months. SCPSA believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues, does not provide any real benefit to Bulk Electric System (BES) reliability, and may have unintended negative consequences on reliability. Often, corrective actions to mitigate these events are local in nature and only require minor additional loss of local load to avoid major projects. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, such that Transmission Planners, customers, and local regulators jointly control the decision making when BES reliability is not an issue. The transparency requirements of the new standard facilitate this type of decision making. In addition, the prohibition on non-consequential load loss for these events creates an incentive for Transmission Planners to remove lines serving load from network (serve the loads radially) so that they are characterized as consequential load. The unintended consequence of the standard would be a reduction in reliability for service to local load.
Suzanne Ritter	Santee Cooper	6	Negative	

Response: Based on your comment and those of others, the SDT has revised the definition of Year One.

> **Year One:** The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013.

The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

Voter	Entity	Segment	Vote	Comment
12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	We find P5, Multiple Contingency (Fault plus Protection System failure to operate) to be confusing. What analysis is required for this? Analysis of individual Protection System component failures or something else? Do the benefits justify this requirement?
Response: The SDT has changed the text for the P5 event as a result of your (and others) comments to address these concerns. **P5**. Delayed Fault Clearing due to the failure of a relay[13] protecting the Faulted element to operate as designed, for a Fault on one of the following: **13**. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	We thank the Standard Drafting Team for their long and dedicated effort to develop this standard. At this time, Hydro One has decided to cast a negative vote with the following comments: 1. Note 3 in Table 1 refers to EHV Facilities (above 300 kV) and HV (300 kV and lower voltage systems) The standards uses this threshold to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. We suggest the following be added to this note: "In the region(s) or area where there is a performance based methodology in place to determine Bulk Electric System (BES) elements (e.g. NPCC), only the BES portion of the system is subject to the Standard." 2. The Standard repeatedly uses the capitalized term "Firm Transmission Service (FTS)." The NERC Glossary of Terms defines FTS as "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." We believe that the use of this term and that of "Transmission Service" in TPL-001-1 should be revised as they do not have the same meaning in all jurisdictions. A clarification within the standard will eliminate this confusion. 3. The Effective Date Section in the proposed standard gives a time of 60 months to implement certain Corrective Actions. We believe this Standard should not explicitly define timelines (5 years in this case) for transmission projects. Regulatory approvals for new or modified transmission systems may take a significant time in some jurisdictions. We suggest changing the wording to say that Transmission mitigation measures for the reliability of the Bulk Electric System must be implemented as soon as practical exercising due diligence. Progress of and/or delays associated with critical project(s) impacting BES reliability should be submitted to the respective regions and NERC. We recognize that Requirement 2.7.3 covers situations that arise beyond the control of the Transmission Planner (TP) or Planning Coordinator (PC), but we believe that the proposed 60 months timeline
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	

Voter	Entity	Segment	Vote	Comment
				should be removed.
Response: This standard applies to the BES. If there are areas of your system that are not BES, then the standard doesn't apply to them. This would be true even if those elements are above 300 kV. No change made. The SDT reviewed the use of Firm Transmission Service and believes that the term is used correctly in the standard. No change made. The SDT has changed the majority of the implementation timeframe from 60 to 84 months as per your (and others') suggestion. Since problems may not be seen until after the assessments are completed and there is a 24 month implementation for assessments, the total time for items P2-1, P2-2 and P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 KV) has been increased to 84 months. P1-2 and P1-3 were not increased since they are already being covered by the implementation plan for Project 2010-11: TPL Table 1 Order. Requirement R2, part 2.7.3 - If an entity can demonstrate that they have made a best faith effort to implement the planned solution then there should not be a concern. The wording of the requirement allows an entity this flexibility.				
Mark Ringhausen	Old Dominion Electric Coop.	4	Negative	While the SDT has made progress in their changes from the first draft, there are still some areas that need to be clarified. Others are proving more specific comments (PJM) so look for their comments and address.
Response: Please see response to PJM.				

Voter	Entity	Segment	Vote	Comment
Richard Salgo	Sierra Pacific Power Co.	1	Negative	While we greatly appreciate the work of the SDT, and feel that this Standard has achieved significant improvement, there are a number of issues precluding our approval as written: Spare Equipment: need a clarification on what the "assessment" of the impact of equipment availability entails. For instance, is the assessment a simple narrative of the necessary operational mitigation, engineering analysis of the impact, or on the other extreme, is it a full repeat of the NERC study work for all potential permutations of long lead-time equipment? We have difficulty accepting the language regarding the loss of non-consequential load. As written, this creates a disincentive for the implementation of incremental reliability improvements in the network; ie, creation of a parallel path that does not fully provide redundancy to load service would drive a violation of the requirement. Lastly, the treatment of firm transmission service from the standpoint that it cannot be curtailed under various contingencies is problematic. As written, it would appear that the single-contingency loss of a contract transmission path would require continuance of the firm transmission service via some alternate parallel path. Such methodology would require all such paths to have redundancy via parallel transmission or result in dramatic reductions in transfer ratings.

Response: The SDT has clarified the wording of the requirement and believes that this will address your concern.

> **Requirement R2, part 2.1.5** - When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment 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 studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

The SDT has added footnote #12 to P1, P2-1, and P3 to address your and others concerns in this area.

> 12. Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.

Footnote 9 states the conditions for when Firm Transmission Service may be curtailed. If what you are describing is actually Conditional Firm, then see footnote 4. No change made.